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*President of the Senate*

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**CHRIS SPROWLS**
*Speaker of the House of Representatives*

May 31, 2022

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

**Re: Docket No. 20220048-EI**

Dear Mr. Teitzman,

Please find enclosed for filing in the above referenced docket the Direct Testimony and Exhibits of Kevin J. Mara, P.E. This filing is being made via the Florida Public Service Commission's Web Based Electronic Filing portal.

If you have any questions or concerns; please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

Richard Gentry
Public Counsel

***/s/Mary A. Wessling***
Mary A. Wessling
Associate Public Counsel
Wessling.Mary@leg.state.fl.us

**CERTIFICATE OF SERVICE**
**DOCKET NO. 20220048-EI**

**I HEREBY CERTIFY** that a true and correct copy of the foregoing has been furnished by electronic mail on this 31st day of May 2022, to the following:

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***/s/Mary A. Wessling***
Mary A. Wessling
Associate Public Counsel

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| In re: Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company. | DOCKET NO. 20220048-EI<br><br>FILED: May 31, 2022 |

# DIRECT TESTIMONY

# OF

# KEVIN J. MARA, P.E.

# ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA


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**DIRECT TESTIMONY**

**OF**

**KEVIN J. MARA**

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20220048-EI

## I. <u>INTRODUCTION</u>

**Q. WHAT IS YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS?**

A. My name is Kevin J. Mara. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067. I am the Executive Vice President of the firm GDS Associates, Inc. ("GDS") and Principal Engineer for a GDS company doing business as Hi-Line Engineering. I am a registered engineer in Florida and 22 additional states.

**Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.**

A. I received a Bachelor of Science degree in Electrical Engineering from Georgia Institute of Technology in 1982. Between 1983 and 1988, I worked at Savannah Electric and Power as a distribution engineer designing new services to residential, commercial, and industrial customers. From 1989-1998, I was employed by Southern Engineering Company as a planning engineer providing planning, design, and consulting services for electric cooperatives and publicly owned electric utilities. In 1998, I, along with a partner, formed a new firm, Hi-Line Associates, which specialized in the design and planning of electric distribution systems. In 2000, Hi-Line Associates became a wholly owned subsidiary of GDS Associates, Inc. and the name of the firm was changed to Hi-Line Engineering, LLC.

In 2001, we merged our operations with GDS Associates, Inc., and Hi-Line Engineering became a department within GDS. I serve as the Principal Engineer for Hi-Line Engineering and am Executive Vice President of GDS Associates. I have field experience in the operation, maintenance, and design of transmission and distribution systems. I have performed numerous planning studies for electric cooperatives and municipal systems. I have prepared short circuit models and overcurrent protection schemes for numerous electric utilities. I have also provided general consulting, underground distribution design, and territorial assistance.

**Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.**

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Orlando, Florida; Manchester, New Hampshire; Kirkland, Washington; Portland, Oregon; and Madison, Wisconsin. GDS has over 170 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, and statistical services. Our clients are primarily publicly owned utilities, municipalities, customers of privately owned utilities, groups or associations of customers, and government agencies.

**Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?**

A. I have submitted testimony before the following regulatory bodies:

- Vermont Department of Public Service
- Florida Public Service Commission

- Federal Energy Regulatory Commission ("FERC")
- District of Columbia Public Service Commission
- Public Utility Commission of Texas
- Maryland Public Service Commission
- Corporation Commission of Oklahoma

I have also submitted expert opinion reports before United States District Courts in California, South Carolina, and Alabama.

**Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?**

A. Yes. I have attached Exhibit KJM-1, which is a summary of my regulatory experience and qualifications.

**Q. ON WHOSE BEHALF ARE YOU APPEARING?**

A. GDS Associates, Inc., was retained by the Florida Office of Public Counsel ("OPC") to review Tampa Electric Company's ("TECO" or "Company") proposed 2022-2031 Storm Protection Plan ("SPP" or "Plan") on behalf of the OPC. Accordingly, I am appearing on behalf of the Citizens of the State of Florida.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. I am presenting my recommendations on behalf of OPC regarding TECO's proposed 2022-2031 Storm Protection Plan. My testimony serves to refute the testimony presented by David A. Pickles, David L. Plusquellic, Richard Latta, and Jason De Stigter regarding the scope of the SPP projects, and whether the programs and projects could qualify to be included in the SPP.

**Q. WHAT INFORMATION DID YOU REVIEW IN PREPARATION OF YOUR TESTIMONY?**

A. I reviewed the Company's filing, including the direct testimony and exhibits. I also reviewed the Company's responses to OPC's and Staff's discovery and other materials pertaining to the SPP and its impacts on the Company. In addition, I reviewed Section 366.96, Florida Statutes, which requires the filing of the SPP and authorized the Commission to adopt the relevant rules, including Rule 25-6.030, Florida Administrative Code ("F.A.C."), which addresses the Commission's approval of a Transmission and Distribution SPP that covers a utility's immediate 10-year planning period, and Rule 25-6.031, F.A.C., which addresses the utilities recovery of costs related to their SPPs.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. I first discuss the purpose of storm hardening and an SPP as informed by Rule 25-6.030, F.A.C., and criteria needed for storm hardening projects. I then discuss principles to be applied when reviewing TECO's proposed SPP. I also address the level of spending by TECO. Finally, I discuss my analysis of the new programs proposed in the SPP, including principles that should be applied when reviewing TECO's proposed SPP. In the discussion of the principles I applied, I include criteria that, in my expert opinion, the Commission must weigh to properly evaluate the sufficiency of the SPP and each SPP program under the statutes and rules governing the SPPs.

## II. <u>REVIEW OF THE PURPOSE OF STORM HARDENING</u>

**Q. PLEASE DISCUSS SECTION 366.96, FLORIDA STATUTES.**

A. Section 366.96, Fl. Stat., addresses storm protection plan cost recovery for investor-owned utilities. The purpose of storm hardening is to "effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers."[1]

The Florida Legislature has directed the Commission to consider "[t]he estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan."[2] But there is no express ceiling or cap on the magnitude of the upgrades or improvements contained in the SPP or on the rate impact to the customers. Again, while the legislature left the ratemaking impact of both of these considerations to the Commission's discretion it appears that they gave the Commission direction and the tools to limit the utilities' spending in the SPP and SPPCRC approvals. As part of my testimony, I will present some recommended limits to the construction programs.

All of the utilities' SPPs are based on the premise that by investing in storm hardening activities the electric utility infrastructure will be more resilient to the effects of extreme weather events. This resiliency means lower costs for restoration from the storms and reduced outage times experienced by the customers. Some programs have a greater impact on reducing outages times and lowering restoration costs than other programs. Clearly, the goal is to invest in storm hardening activities that benefit the customers of the electric utilities at a cost that is reasonable relative to those benefits.

[1] Section 366.96 (1)(d), Florida Statutes.
[2] Section 366.96 (4)(c), Florida Statutes.

**Q. PURSUANT TO SECTION 366.96, FL. STAT., THE COMMISSION ADOPTED RULE 25-6.030, F.A.C. PLEASE DISCUSS RULE 25-6.030, F.A.C., FROM YOUR PERSPECTIVE AS AN ELECTRIC UTILITY DISTRIBUTION ENGINEER.**

A. Rule 25-6.030, F.A.C., mandates a storm protection program, which is a group of storm protection projects to enhance the utility's existing infrastructure for "the purpose of reducing restoration costs and reducing outages times associated with extreme weather conditions ... "[3] Further, a storm protection *project* is defined as a specific activity designed for enhancement of the system "for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions ... "[4]

Clearly, this two-prong test to reduce restoration costs and reduce outage times as defined in Rule 25-6.030, F.A.C., must be applied to storm protection programs and projects. A project must accomplish both benefits, reduction in restoration costs, and reduction in outage time to be included in the SPP.

Logically, strengthening the electric utility infrastructure is a storm plan requirement and simply replacing like-for-like equipment with the same strength and functionality does not meet the requirements of Rule 25-6.020, F.A.C. The point of the SPP is to enhance the strength of the grid to withstand extreme weather conditions that result in high winds.

Thus, there are two criteria that must be central in each SPP program and project:

(1) Reduce restoration costs, and

(2) Reduce outage times.

Rule 25-6.030, F.A.C., requires utilities to provide budgets for programs and to provide the estimated reduction in restoration costs.[5] These amounts must be balanced

[3] Rule 25-6.030 (2)(a), F.A.C.
[4] Rule 25-6.030 (2)(b), F.A.C.
[5] Rule 25-6.030 (3)(d)(1). F.A.C.

against the benefits to the utilities' customers. Further, the two amounts will allow the Commission and stakeholders to understand the benefits of the capital investments for storm hardening relative to the "reasonableness" of the costs. Any program can claim to reduce outage costs and outage time; however, the program must be cost effective for customers to benefit. To summarize, the Rules require a two-prong test for consideration of a program: reduction in outage costs and reduction in outage time.

**Q. CAN YOU PROVIDE AN ILLUSTRATIVE EXAMPLE OF HOW A STORM HARDENING PROJECT MEETS THE TWO CRITERIA OF RULE 25-6.030 F.A.C.?**

A. Yes. Hardening means to design and build components of the system to a strength that would not normally be required. For instance, distribution poles per the National Electrical Safety Code ("NESC") need only be built based on loading requirement of Rule 250B (60 MPH wind) and Grade C strength. Hardening would specify poles be built based on loading requirements of Rule 250C extreme wind (120-140 MPH) and Grade B strength factors.[6] By installing poles with greater strength needed to meet this new design criteria, these hardened poles will reduce restoration costs because there will be fewer pole failures and will reduce restoration time because there will be fewer failed poles to repair.

Simply replacing a pole using the same loading requirements and same strength factors as the original pole will not harden the system. A like-for-like replacement will result in a stronger pole only because it is new, but the performance of the like-for-like replacement will be the same over time. For instance, in transmission system hardening, many utilities are using non-wood poles (steel or concrete) to replace existing wood poles. The upgrade to non-wood poles is not required by the NESC but these non-wood poles

[6] The loading of NESC Rule 250C and Grade B do not normally apply to distribution lines.

have proven to reduce outages and reduce outage times due to the superior ability of the non-wood pole to survive during extreme windstorms.

Alternately, replacing aging infrastructure with new infrastructure of the same strength or purpose does not harden the system. This is because using the same strength components does not reduce outage times nor outage costs when compared to the original components.

**Q. CAN YOU PROVIDE EXAMPLES OF CHANGES TO AN ELECTRIC UTILITY SYSTEM WHICH DO NOT MEET THE CRITERIA SET FORTH IN RULE 25-6.030 F.A.C.?**

A. Yes. Adding new sectionalizing equipment such as reclosers, fuses, and disconnect switches does not reduce outages. The outage will still occur and will still need to be repaired; thus, there is no change to the restoration costs. These devices only help to isolate a smaller portion of the system that is affected by the outage. Thus, the devices fail the criteria in 25-6.030 F.A.C. While the devices do reduce outage times, they fail to reduce outage costs. Further, adding sectionalizing equipment does not strengthen or harden the system.

Another example is replacement of a bridge on an access road. The bridge does not reduce outages. It can help with access to the transmission right-of-way. However, the purpose of the bridge originally was, and continues to be, to allow access. Replacing the bridge to allow access does not change its purpose. The utility has a responsibility to maintain its infrastructure and if the bridge is old and in disrepair it needs to be replaced as a normal course of business and would not qualify as a storm protection project.

While not proposed in Tampa Electric's filing, the following is an example to illustrate how utilities could expand the SPP programs if the Commission does not adhere to the stringent two-prong test for the program. For example, purchasing a new replacement line truck which is more fuel efficient does not reduce outages. It could be argued that it reduces outage costs by being more fuel efficient. Also, since the truck is new, one could argue that it is more reliable and therefore would reduce outage times. However, this type of program does not reduce outages. It does not strengthen or harden the system, and in my opinion, would not meet the requirements of the statute.

**Q. WHAT OTHER TYPES OF PROGRAMS DO YOU BELIEVE SHOULD BE EXCLUDED FROM THE SPP PROGRAMS?**

A. An electric utility has as a core responsibility to maintain a safe operating system. To that end, aging infrastructure and deteriorated equipment needs to be maintained in safe operating condition. Failure to meet this core responsibility puts the public at risk. However, simply replacing old equipment does not constitute storm hardening. The approved storm hardening programs started with replacement of old poles with stronger poles designed for extreme wind experienced during storms above what is necessary to meet the requirements of the National Electric Safety Code. This hardening was characterized by stronger than required components and timed improvements so that as poles failed inspection, the system would be naturally strengthened over a period of time.

In Tampa Electric's current 2022-2031 SPP filing there are several programs such as installation of automation equipment, reclosers, trip savers, vegetation contact detection, locational awareness, access roads, and bridges that are **not** storm hardening programs. These are aging infrastructure programs which do not decrease outage costs and do not reduce outage time when compared to equivalent existing system infrastructure. Tampa Electric should be implementing the renewals of aging infrastructure through base rates rather than SPP projects primarily because these programs do not meet the two-prong test of Rule 25-6.030 F.A.C. Instead, these programs are more correctly classified as ordinary replacements and should be treated using standard rate base.

**Q. CAN ALL COSTS THAT REDUCE OUTAGE COSTS, REDUCE OUTAGE TIMES AND STRENGTHEN THE ELECTRIC UTILITY INFRASTRUCTURE BE INCLUDED IN THE SPP AND SPPCRC?**

A. Section 366.96, Florida Statutes and Rule 25-6.030, F.A.C. provide no overt governance regarding limitations to the costs of SPP programs. Even by Tampa Electric's own analysis, some programs provide very minor improvement to cost reductions and reductions in outage times while costing significantly more than these marginal savings projections. It is imperative that the Commission consider implementing guidelines to limit the magnitude of each program's costs compared to its benefits. For this reason, and on behalf of the customers who must bear these costs against the level of projected benefits, elsewhere in my testimony, I propose my limits to certain projects for the Commission to consider in the public interest.

**Q. DID YOU COMPARE THE 10-YEAR COSTS OF TAMPA ELECTRIC'S 2020-2029 SPP AND ITS 2022-2031 SPP?**

A. Yes, there is an increase of 7% in capital expenditures proposed by Tampa Electric. The table below shows an increase of over $109 million in capital spending over the 10-year plan.

| Capital | Total 2020-2029 SPP $millions | Total 2022-2031 SPP $millions | Difference | Percent increase |
|---|---|---|---|---|
| Distribution Lateral Undergrounding | $ 976.81 | $ 1,070.20 | $ 93.39 | 10% |
| Transmission Asset Upgrades | $ 149.12 | $ 139.12 | $ (10.00) | -7% |
| Distribution - Substation Extreme Weather Protection | $ 32.37 | $ 15.30 | $ (17.07) | -53% |
| Transmission - Substation Extreme Weather | $ - | $ 13.50 | $ 13.50 | |
| Distribution Overhead Feeder Hardening | $ 289.73 | $ 316.90 | $ 27.17 | 9% |
| Transmission Access Enhancements | $ 14.73 | $ 31.45 | $ 16.72 | 114% |
| Distribution Pole Replacements | $ 126.05 | $ 112.27 | $ (13.78) | -11% |
| Total Capital | $ 1,588.81 | $ 1,698.74 | $ 109.93 | 7% |

| O&M | Total 2020-2029 SPP $millions | Total 2022-2031 SPP $millions | Difference | Percent increase |
|---|---|---|---|---|
| Distribution Lateral Undergrounding | $ - | $ 2.03 | $ 2.03 | |
| Distribution Vegetation Management - planned | $ 246.31 | $ 277.02 | $ 30.71 | 12% |
| Distribution Vegetation Management - unplanned | $ 12.10 | $ 13.50 | $ 1.40 | 12% |
| Transmission Vegetation Management - planned | $ 32.95 | $ 34.25 | $ 1.30 | 4% |
| Transmission Vegetation Management - unplanned | $ - | $ - | $ - | |
| Transmission Asset Upgrades | $ 2.98 | $ 5.60 | $ 2.62 | 88% |
| Distribution - Substation Extreme Weather Protection | $ - | $ - | $ - | |
| Transmission - Substation Extreme Weather | $ - | $ - | $ - | |
| Distribution Overhead Feeder Hardening | $ 8.92 | $ 7.94 | $ (0.98) | -11% |
| Transmission Access Enhancements | $ - | $ - | $ - | |
| Distribution Infrastructure Inspections | $ 10.46 | $ 11.17 | $ 0.71 | 7% |
| Transmission Infrastructure Inspections | $ 5.09 | $ 5.88 | $ 0.79 | 16% |
| SPP Planning & Common | $ 3.10 | $ 9.39 | $ 6.29 | 203% |
| Other Legacy Storm Hardening Plan Items | $ 3.01 | $ 3.14 | $ 0.13 | 4% |
| Distribution Pole Replacements | $ 6.93 | $ 7.23 | $ 0.30 | 4% |
| Total O&M | $ 331.85 | $ 377.15 | $ 45.30 | 14% |

**Q. HAVE YOU COMPARED THE COSTS ON A PER RATEPAER BASIS FOR THE INVESTOR-OWNED UTILITIES WHO HAVE FILED SPP PLANS?**

A. Yes. I looked at the ratio of capital spending to the number of customers for the 2020-2029 SPP and the 2022-2031 SPP for the electric utilities who filed plans. This information is shown in the following table:

**Total 10-year Projected SPP Investment per Customer**
**Includes only Capital Investment**

| | Customers Total | 2020 SPP 10-Year Capital $Millions | 2020 SPP $/Customer | 2023 SPP * 10-Year Capital $Millions | 2023 SPP $/Customer |
|---|---|---|---|---|---|
| FPUC | 32,993 | N/A | | $ 243 | $ 7,369 |
| Tampa Electric | 824,322 | $ 1,589 | $ 1,928 | $ 1,699 | $ 2,061 |
| Duke Energy Florida | 1,879,073 | $ 6,635 | $ 3,531 | $ 7,318 | $ 3,894 |
| Florida Power & Light | 5,700,000 | $ 11,244 | $ 1,973 | $ 13,908 | $ 2,440 |

* FPUC's and TECO's plans dated 2022 for a 10-year period

Note that TECO and Florida Public Utilities Company refers to their plans as a 2022-2031 SPP and other utilities use 2023-2032 in reference to their plans.

**Q. IN YOUR OPINION, WHAT ARE THE CURRENT LIMITS ON THE SPP BUDGETS?**

A. From my understanding of Tampa Electric's SPP filing, Tampa Electric determined annual funding levels based in part on "a constrained labor market."[7] In my opinion, the only practical limit to the magnitude of the SPP budgets was the limitation of resources in terms of engineers and construction personnel realistically available to complete the annual goals of the program.

Further, Tampa Electric and its consultant 1898 & Co. developed what they referred to as "the optimal point before additional investment does not result in materially greater restoration costs and outage time benefits."[8] It is apparent that this analysis ignored the rate impact to customers.

Tampa Electric testified that the customer rate impacts are examined as an end result and are not used to determine the total level of capital spending.[9] The company

[7] Direct Testimony of David Pickles p. 11, lines 21-25 and p. 12, lines 1-8.
[8] Direct Testimony of David Pickles p. 28, lines 10-18.
[9] *See* Exhibit KJM-2, TECO Response to OPC's Second Set of Interrogatories, Interrogatory No. 50.

analysis determined that the expected bill impact was reasonable in comparison with the projected benefits of the investment.[10] In my opinion the SPP for Tampa Electric and the other utilities is not reasonable and should be constrained to limit the rate impact on customers during a time of higher than average inflation.

## III. SUMMARY OF PROPOSED SPP REDUCTIONS

**Q. CAN YOU SUMMARIZE YOUR PROPOSED REDUCTIONS IN TAMPA ELECTRIC'S PROGRAMS?**

A. The table below summarizes my recommendations to reduce the 10-year SPP capital budget by $851 million. These recommendations are detailed in the testimony.

| Capital | Total 2022-2031 SPP $Millions | Reductions Proposed by Mara | Net 2022-2031 SPP $Millions | Reason for Reduction |
|---|---|---|---|---|
| Distribution Lateral Undergrounding | $ 1,070 | $ (570) | $ 500 | Limit impact to customers |
| Transmission Asset Upgrades | $ 139 | $ - | $ 139 | |
| Distributon - Substation Extreme Weather | $ 15 | $ (15) | $ - | Does not comply with 25-6.030 |
| Transmission - Substation Extreme Weather | $ 14 | $ (14) | $ - | Does not comply with 25-6.030 |
| Distribution Overhead Feeder Hardening | $ 317 | $ (217) | $ 100 | Limit impact to customers |
| Transmission Access Enhancements | $ 31 | $ (31) | $ - | Does not comply with 25-6.030 |
| Distribution Pole Replacements | $ 112 | $ - | $ 112 | |
| Total Capital | $ 1,699 | $ (847) | $ 851 | |

The reductions I am proposing will result in a capital cost per customer of $1,088.

**Q. IF LIMITS ARE PLACED ON THESE PROGRAMS, DOES THAT REDUCE BENEFITS OF THE SPP?**

A. Yes, it does. However, the reduction in benefits must be balanced against the impact to the rate payers. In fact, the United States is experiencing its worst inflation in 40 years, and consumers have seen steep increases in the price of gas and groceries, as well as escalating electric bills, specifically in Florida. Excessive burdens on the rate payers would

[10] *See* Exhibit KJM-3, TECO Response to OPC's Second Set of Interrogatories, Interrogatory No. 39.

result from unchecked spending on SPP programs unless the Commission acts to limit the expenditures.

Tampa Electric stated they worked with their consultant 1989 & Co. to confirm that the company's projected funding levels are at the optimal point before additional investment does not result in materially greater restoration costs and outage times.[11] This may be true, but the benefits are based on a 50-year net present value implementation duration.[12] In my opinion, prioritizing feeders and laterals, poles, and other equipment that is the most vulnerable to extreme storms provides greater impact in the early stages of the program which is not depicted in Tampa Electric's analysis. Also, Tampa Electric's plan for optimization did not consider the impact to the rate payers.

While I am not fully confident in the benefit analysis developed by 1898 & Co. on behalf of Tampa Electric, I considered the results as a means to determine an overall capital budget for rate payers. Specifically, using Figure 6-1 from Tampa Electric's *2022-2031 Storm Protection Plan Resilience Benefits Report*,[13] I determined that a capital spending budget of $850 million would yield approximately $3.25 billion in net benefits. This capital budget reduction to $850 million is consistent with my recommendations detailed in my testimony. Comparing this to the $3.5 billion in benefits from a capital budget of $1.5 billion, it seems intuitively obvious that spending half of the capital and achieving 92% of the benefits (3.25 divided by 3.5) would be a far better yield for rate payers.

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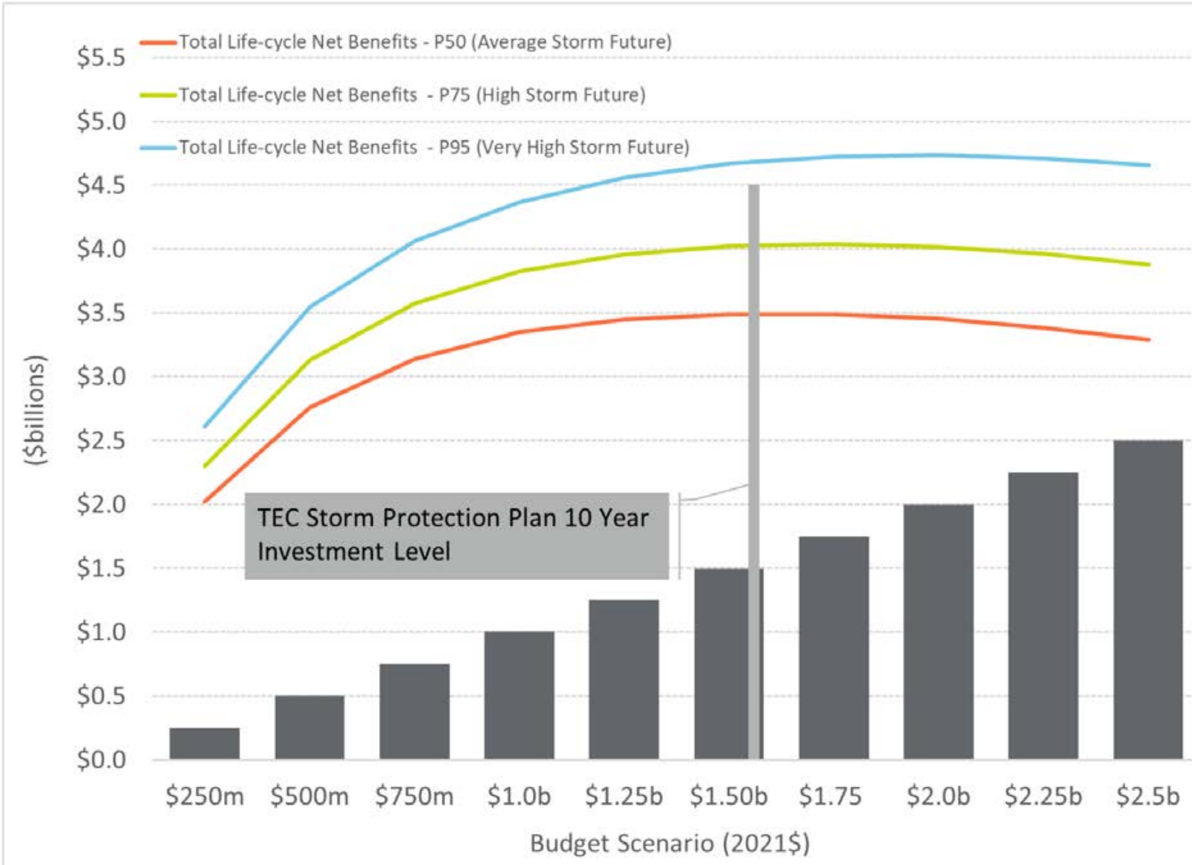
[11] Direct Testimony of David Pickles p. 28, lines 14-18.
[12] *See* Exhibit DAP-1, Appendix F, p. 15 of 82.
[13] *See* Exhibit DAP-1, Appendix F, p. 71 of 82.

**Figure 6-1: Budget Optimization Results**




**Q. DO THE BENEFITS OF THESE PROGRAMS SEEM TO BE DEPENDENT ON THE RETURN PERIOD OF THE EXTREME WEATHER EVENTS?**

A. Yes, the magnitude of benefits is based on the return period of storms meaning how frequently the electric utility's service area is impacted by a major storm. The goal is to reduce hurricane restoration costs that are imposed on customers. It is important to consider the recent history of weather events impacting Florida. After a catastrophic two-year period in 2004 and 2005, the Commission undertook to require storm hardening measures. As the companies began implementing these measures, Florida embarked on a 10-year period of tropical storm relative quiet, with no major storms impacting the state until 2016.

In 2016, a five-year period of major storms began. Over this period the five investor-owned electric utilities have reported the following costs from named hurricanes and tropical storms:

Reported Costs from Named Tropical Storms for Each Florida Investor-Owned Utility
2016 Through 2020
$ Millions

| | Storm | FPL | Duke | Gulf | TECO | FPUC | Total |
|---|---|---|---|---|---|---|---|
| 2016 | Matthew | 310.3 | 40.0 | | 1.0 | 0.6 | 351.9 |
| 2016 | Hermine | 21.2 | 28.6 | | 5.7 | 0.0 | 55.5 |
| 2016 | Colin - TS | | 3.6 | | 2.5 | | 6.1 |
| 2017 | Irma | 1,378.4 | 464.1 | | 101.7 | 2.3 | 1,946.5 |
| 2017 | Nate | | 5.3 | | | | 5.3 |
| 2017 | Cindy - TS | | | | | 0.0 | 0.0 |
| 2018 | Michael | | 316.5 | 427.7 | | 67.3 | 811.5 |
| 2018 | Alberto - TS | | 1.0 | | | | 1.0 |
| 2019 | Dorian | 240.6 * | 153.0 * | | | 1.2 * | 394.7 |
| 2019 | Nestor - TS | | 0.6 | | | | 0.6 |
| 2020 | Sally | | | 227.5 | | | 227.5 |
| 2020 | Zeta | | | 11.4 | | | 11.4 |
| 2020 | Isaias | 68.5 | 1.1 | | | | 69.5 |
| 2020 | Eta - TS | 115.9 | 20.8 | | | | 136.7 |
| Total All Years | | 2,134.9 | 1,034.5 | 666.6 | 111.0 | 71.4 | 4,018.4 |

Note: The reported costs included above represent the actual total Company restoration costs included in each petition filed with the FPSC. They do not include reductions for costs capitalized or determined to be non-incremental (ICCA). They also do not include carrying charges or impacts from requested changes to storm reserve balances. Finally, they do not include changes due to later Company modifications, settlements, and/or any other FPSC action.

* Expenses are mostly all preparation costs because the storm did not make landfall in Florida.

Tampa Electric's estimate for annual avoided restoration costs for the 10-year SPP ranges from $380 million to $531 million.[14] This is based on an assumption of the program developed by 1898 & Co. that the status quo restoration costs would range from $963 million to $1.313 million. However, the 5-year period actual restoration costs for Tampa Electric are $111 million. The comparison of the 5-year actual costs to the estimated 50-year NPV status quo estimate does not provide much confidence in the Monte Carlo Simulation of future storms.[15]

**Q. YOU NOTE THAT EXPENSES RELATED TO HURRICANE DORIAN ARE MOSTLY FOR PREPARATION AND STAGING. DOES DUKE CLAIM THAT THEIR SPP WILL RESULT IN LESS PRE-STORM STAGING THEREFORE REDUCING COSTS?**

A. No. I am not aware that any of the Florida utilities have committed to reducing the number of contractors that the company pre-stages ahead of a storm due to implementing its SPP programs. The SPP's do not claim to reduce costs in this regard, but if the system is hardened, at some point a company should logically spend less on pre-staging and would be expected to limit the amount of staging they do ahead of a storm in conjunction with the SPP.

[14] *See* Exhibit DAP-1, Appendix F, p. 75 of 82.
[15] *See* Exhibit DAP-1, Appendix F, p. 63 of 82.

## IV. REVIEW OF SPP PROJECTS

**Q. CAN YOU EXPLAIN THE SUBSTATION EXTREME WEATHER HARDENING PROGRAM?**

A. Yes. This program is designed to modify substations that have the potential for flooding or storm surges. Tampa Electric identified 56 out of 216 substations with some level of flood risk.[16] The Program is divided into distribution substations and transmission substations.[17]

**Q. WHAT IS YOUR UNDERSTANDING OF BUILDING SUBSTATIONS IN COASTAL FLOOD ZONES?**

A. The acquisition of land for a substation is always a challenge but the land needs to be suitable for safe, and reliable electric service. Flood maps were not issued until 1973[18] so substations constructed before 1973 would not have had standards requiring certain elevations. Details of improvements are not required to be contained in the current SPP. However, Tampa Electric identified some substations that may have capital upgrades including the South Gibsonton 230/69kV Substation and the Skyway 69kV Substation.[19] However, Tampa Electric did a major upgrade on South Gibsonton 230/69kV Substation between 1999 to 2002[20] which is after 1973. Therefore, Tampa Electric should have designed this upgrade with the knowledge of potential flood waters and designs should have accounted for this predictable occurrence. More recently the Skyway Substation had a major upgrade in 2010 and modifications for possible flooding should have been done at that time. Specifically, the *Standard ASCE-24-14 Flood Resistant Design and*

[16] *See* Exhibit DAP-1, p. 42 of 78.
[17] *See* Exhibit DAP-1, p. 70 of 78.
[18] *See* Exhibit KJM-4, *A Chronology of Events Affecting the National Flood Insurance Program,* FEMA, pp. 14-15.
[19] *See* Exhibit DLP-1, Document No. 5, pp. 1 to 55.
[20] *See* Google Earth Pro historic images

*Construction* provides minimum requirements for design and construction of structures located in flood hazard areas. This standard recommends the facilities be designed for the Basic Flood Elevation (100-year flood level) plus two feet. Since the details of improvements are not required to be contained in the current SPP, no conclusion can be reached regarding prudence of the original design and the proposed mitigation plans.

**Q. ARE THERE OTHER MEANS AVAILABLE TO REDUCE OUTAGE TIMES FOR CUSTOMERS DUE TO FLOODING OF SPECIFIC SUBSTATIONS?**

A. Yes. It is my belief that most of Tampa Electric's distribution system is designed for a single contingency failure which is consistent with design of modern distribution systems in suburban and urban areas. Single contingency means designing for the loss of one feeder or one substation transformer. Thus, if a transformer has to be de-energized for flooding it is very likely that the load from this substation can be switched to an adjacent substation that is not flooded. To the extent the case, the Substation Extreme Weather Hardening Program does not reduce outage time and therefore should be excluded from the SPP in accordance with the statute that contemplates reduction in both outage time and restoration costs.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE DISTRIBUTION - SUBSTATION EXTREME WEATHER PROTECTION PROGRAM AND TRANSMISSION-SUBSTATION EXTREME WEATHER PROTECTION PROGRAM?**

A. I recommend inclusion of these programs on a limited basis. The programs should exclude any substation that has alternate feeds to allow the substation to be de-energized due to flooding. The programs should also exclude any substation that has not had a history of flooding. The exclusions from the programs are substations that do not meet the requirements of Rule 25-6.030, F.A.C., for a known benefit of the project. The 10-year capital budgets for the Distribution-Extreme Weather Protection Program and Transmission- Extreme Weather Protection Program are $15.3 million and $13.5 million respectively.[21] As I have suggested, I doubt many substations will qualify for the SPP and therefore these SPP costs will be reduced to essentially $0.

**Q. CAN YOU EXPLAIN THE DISTRIBUTION OVERHEAD FEEDER HARDENING PROGRAM?**

A. Yes. This program is two major projects: Feeder Strengthening and Feeder Sectionalizing and Automation.[22] The Feeder Strengthening project will harden selected feeders to the NESC Grade B construction with extreme wind loading from Rule 250C.[23] The Distribution Feeder Sectionalizing and Automation project involves adding more automation equipment to allow automatic transfer of load to minimize the number of customers suffering from a prolonged outage.[24] This type of system is also referred to as a Self-Optimizing System. The Distribution Feeder Sectionalizing and Automation program also includes upgrading conductor sizes to allow for increased loading that could occur from the system reconfiguration.[25] These two projects are applied to a feeder simultaneously.[26]

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[21] *See* Exhibit DAP-1, p. 70 of 78.
[22] *See* Exhibit DAP-1, p. 44 of 78.
[23] *See* Exhibit DAP-1, p. 44 of 78.
[24] *See* Exhibit DAP-1, p. 44 of 78.
[25] *See* Exhibit DAP-1, p. 45 of 78.
[26] *See* Exhibit DAP-1, p. 45 of 78.

**Q. ARE THERE ANY NEW PROJECTS ASSOCIATED WITH THE DISTRIBUTION OVERHEAD FEEDER HARDENING PROGRAM?**

A. Yes. Tampa Electric is proposing to leverage AMI data with three new applications: locational awareness, vegetation contact detection, and storm mode.[27]

**Q. WHAT IS YOUR RECOMMENDATION FOR THE DISTRIBUTION FEEDER STRENGTHENING PROJECT?**

A. Tampa Electric is similar to other utilities in Florida in that Tampa Electric has changed its design criteria for distribution feeders. Their new standard is designing for Grade B overload and strength factors with extreme wind loading. I believe that this standard will help to reduce damage during extreme wind events and thereby reduce restoration costs and outage times.

Tampa Electric did not provide a budget breakdown of capital budgets to isolate just the Feeder Strengthening project. However, I suggest that this program be limited to budgets contained in the 2020-2029 SPP[28] which I suggest should be approximately $10 million per year for a total 10-year capital budget of $100 million.

**Q. DOES THE DISTRIBUTION FEEDER SECTIONALIZING AND AUTOMATION PROJECT REDUCE RESTORATION COSTS AND REDUCE OUTAGE TIMES?**

A. No. This project does not reduce the number of outages. Instead, the system is designed to limit the outage to the smallest segment of the system which reduces outage times. For example, if a fuse is added to a lateral and a tree falls on that lateral, the fuse opens and isolates the failed portion of the system. Only a few customers are affected by the outage,

[27] *See* Exhibit DAP-1, p. 46 of 78.
[28] *See* Exhibit KJM-5, Docket No. 20200067-EI, Tampa Electric's 2020-2029 Storm Protection Plan Summary, p. 44.

but the repair costs to remove the tree from the line and perhaps replace a pole are the same whether a fuse is on the lateral or not. The sectionalizing equipment and automation is more complex but acts in a similar fashion except it uses automation to switch and isolate an outage to the smallest portion of the system. Thus, there is no reduction in restoration costs for the automated sectionalizing system. These devices and systems reduce the outage times for some individuals on the system, but do not reduce outage restoration costs because the outage (component failure) will still occur.

**Q. DOES THE AUTOMATION OF THE DISTRIBUTION FEEDER SYSTEM FOR FAULT ISOLATION WORK DURING EXTREME WEATHER EVENTS?**

A. It is my belief that the automation system is not effective during an extreme weather event. For example, if there is a fault on a feeder, the fault isolation system would automatically transfer un-faulted sections of the feeder to an adjacent feeder. However, during a widespread extreme weather event it is doubtful that adjacent feeders will be available because these adjacent feeders will likely have suffered an outage as well.

On blue sky days[29] and even on gray sky days[30], the fault isolating system should be very effective in reducing outage times. But to meet Rule 25-6.030, F.A.C., a program shall have a "purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability."[31] This new system does not meet this requirement since it does not meet the requirement of reducing restoration costs. Tampa Electric has provided no evidence of reduction in outage restoration costs simply by employing more sectionalizing equipment.

[29] *See* Exhibit KJM-6, Blue sky outages: An outage on a day without major storms of other potential external sources of service interruption. (Source: Dr. Paul Stockton, *Resilience for Black Sky Days*, a report for NARUC, February 2014, p. 4.).
[30] *See* Exhibit KJM-6, Gray sky outage: An outage resulting from impact with low-intensity weather events. (Source: Dr. Paul Stockton, *Resilience for Black Sky Days*, a report for NARUC, February 2014, p. 4.).
[31] Rule 25-6.303 (2)(a), F.A.C.

I understand that the 1898 & Co. model for predicting outage reduction assumed that with more sectionalizing in place there would be a limit to the number of customers affected by an outage. That limit is the number of customers on the segment between sectionalizing equipment. However, this assumption is incorrect because the self-healing system would not be fully functional during an extreme weather event. It is my opinion the reduction in outage time is overstated by 50% to 66%.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE DISTRIBUTION FEEDER SECTIONALIZING AND AUTOMATION PROJECT?**

A. I recommend this project be eliminated from Tampa Electric's SPP because it fails to meet the purpose set forth in Rule 25-6.030(2)(a), F.A.C. which requires a project to meet a two-prong test of reduction of restoration costs <u>and</u> reduction in outage times. Specifically, the project does not reduce restoration costs.

**Q. CAN YOU EXPLAIN THE PURPOSE OF THE THREE NEW APPLICATIONS TO THE DISTRIBUTION OVERHEAD FEEDER HARDENING PROGRAM?**

A. Yes, but only to some degree because these programs were not clearly defined in Tampa Electric's filings. Essentially these applications appear to be part of an Outage Management System tied to AMI meters which helps to locate faults on the system. Individually these applications do not reduce outage costs because the fault still needs to be repaired. The Storm mode is only a reporting function[32] and has a very limited impact on reduction in outage times or restoration costs.

[32] *See* Exhibit DAP-1, p. 46 of 78.

**Q. WHAT IS YOUR RECOMMEDNATION REGARDING OF THE THREE NEW APPLICATIONS TO THE OVERHEAD FEEDER HARDENING PROGRAM?**

A. I recommend this project be eliminated from Tampa Electric's SPP because it fails to meet the purpose set forth in Rule 25-6.030(2)(a), F.A.C. which requires a project to meet a two-prong test of reduction of restoration costs <u>and</u> reduction in outage times. Specifically, the project does not reduce restoration costs.

**Q. CAN YOU EXPLAIN THE DISTRIBUTION LATERAL UNDERGROUNDING PROGRAM?**

A. Yes. The Distribution Lateral Undergrounding program converts existing overhead distribution facilities to underground facilities.[33] Tampa Electric has 4,441 miles of overhead lateral lines.[34] The laterals are prioritized based on a cost-benefit NPV ratio. This is coupled with consideration of electrically connected lateral segments.[35]

**Q. DOES THIS PROGRAM REDUCE THE COST OF RESTORATION AND REDUCE OTUAGE TIME CAUSED BY EXTREME WEATHER EVENTS.**

A. Yes. By undergrounding laterals, Tampa Electric reduces outage times and outage costs as evidenced by Tampa Electric in their comparison of historical performance of overhead and underground laterals during and following Hurricane Irma.[36] In addition, Mr. Pickles provided a table showing the decrease in restoration cost and the decrease in customer minutes interrupted in percentages for lateral undergrounding.[37]

[33] Direct Testimony of David L. Plusquellic, p. 14.
[34] Direct Testimony of David L. Plusquellic, p. 14.
[35] Direct Testimony of David L. Plusquellic, p. 14 and p. 15.
[36] *See* Exhibit DAP-1, p. 31 of 78.
[37] *See* Exhibit DAP-1, p. 71 of 78.

**Q. WHAT IS THE MAGNITUDE OF THE DISTRIBUTION LATERAL UNDERGROUNDING PROGRAM?**

A. The total ten-year budget for the program is $1,072.23 million[38] and represents over 60% of the capital costs for all of Tampa Electric's 2022-2031 SPP programs.

**Q. HOW DID TAMPA ELECTRIC DETERMINE THE MAGNITUDE OF THE DISTRIBUTION LATERAL UNDERGROUNDING PROGRAM?**

A. Tampa Electric used several factors, one of which was a review of the labor market to determine what was achievable.[39]

**Q. IN YOUR OPINION IS THE PACE OF UNDERGROUNDING LATERALS AS PROPOSED NECESSARY?**

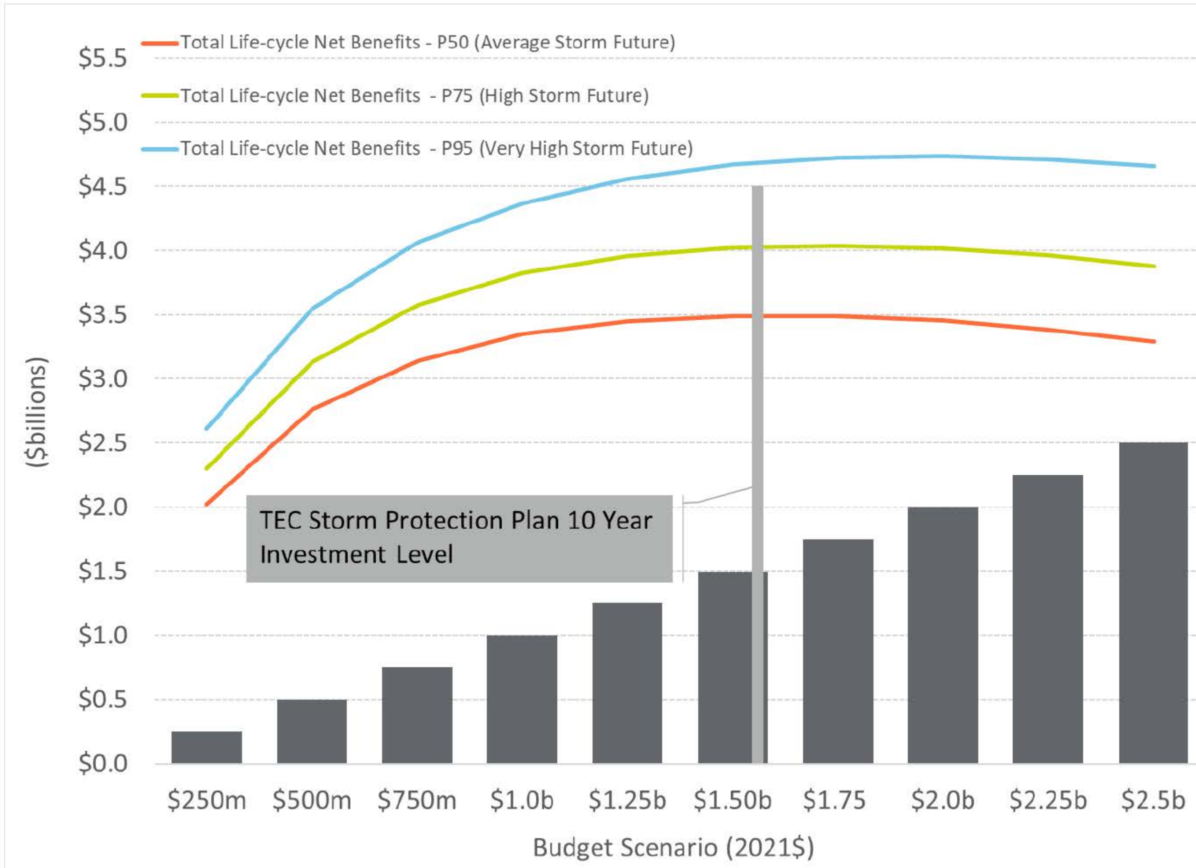
A. No. The statute does not prescribe the pace for storm hardening. This is left to the utilities to determine. Of course, more undergrounding means better resiliency, but this must be balanced with the cost impact to the customers. Tampa Electric's capital expenditures for the 2020-2029 SPP 10-year plan was $976.81 million.[40] Tampa Electric is proposing to increase the 2020 budget by 10% to $1,072.23 million.[41]

I recommend that the Distribution Lateral Undergrounding Program be held to spending roughly $50 million per year. This reduces the total 10-year budget from $1,072 million to $500 million.

While the spending level is lower, the biggest benefits are derived from hardening the worst performing laterals which are the laterals to be undergrounded first. Therefore,

[38] *See* Exhibit DAP-1, p. 71 of 78.
[39] Direct Testimony of Pickles, p. 19, lines 10-13.
[40] *See* Exhibit KJM-5, Docket No. 20200067-EI, Tampa Electric's 2020-2029 Storm Protection Plan, p. 67.
[41] *See* Exhibit DAP-1, p. 70 of 78.

I believe the lower level of spending better balances the rate impact of the spending with the benefits. This is exhibited in Tampa Electric's Budget Optimization Graph.[42]




The Distribution Lateral Undergrounding Program is 60% of the total SPP budget and drives much of the costs and benefits shown in this graph. By reducing spending by $0.5 billion from $1.5 billion to 1.0 billion, the benefits are reduced only slightly from $3.5 billion for an average storm future to $3.35 billion. Inversely stated, starting with a budget of $1.0 billion and increasing to $1.5 billion only results in an increase in benefits of $0.15 billion which is not a prudent investment of capital.

[42] *See* Exhibit DAP-1, Appendix F, p. 71 of 82.

**Q. TAMPA ELECTRIC IS BUILDING AN INVENTORY OF DESIGNED AND PERMITTED UNDERGROUNDING PROJECTS. WHAT CONCERNS DO YOU HAVE ABOUT THIS INVENTORY OF PROJECTS?**

A. My concern is that an inventory or backlog of engineered projects could result in projects that either are never built or have to be re-engineered. My understanding is the true-up of projects in the SPPCRC will include next year's projects and as well as CWIP. However, we cannot analyze prudence until the project is complete (used and useful). In fact, we do not know if the projects will even be finished. Thus, building an inventory of engineered projects limits the Commission's ability to determine prudence for approved funds unless the engineering for these projects is excluded from the SPPCRC until the project is complete.

**Q. CAN YOU EXPLAIN THE TRANSMISSION ACCESS ENHANCEMENT PROGRAM?**

A. Yes. This program is supposed to ensure that Tampa Electric has access to its transmission facilities for the performance of restoration.[43] The program is divided into two projects: access roads and access bridges. The access roads project will restore access to areas where changes in topography and hydrology have negatively impacted existing access roads.[44] The budget for the program to improve access roads is $19.8 million over ten years.[45] The access bridge project will enhance or replace Tampa Electric's system of bridges used to access transmission facilities.[46] The budget for the program to provide improved access bridges is $11.6 million over ten years.[47]

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[43] *See* Exhibit DAP-1, p. 47 of 78.
[44] *See* Exhibit DAP-1, p. 47 of 78.
[45] *See* Exhibit DAP-1, p. 48 of 78.
[46] *See* Exhibit DAP-1, p. 49 of 78.
[47] *See* Exhibit DAP-1, p. 50 of 78.

**Q. DID TAMPA ELECTRIC DESCRIBE ALTERNATIVES TO THE NEWLY PROPOSED TRANSMISSION ACCESS ENHANCEMENT PROGRAM?**

A. No. A viable alternative is the use of specialized equipment to access difficult terrain including track vehicles, large tire vehicles and floating equipment. Purchasing and maintaining these specialized vehicles will likely be more cost effective than expending $31.5 million for road enhancements. Further these road enhancements and specialized vehicles will both require maintenance. Another concern is that the roads may not be passable for normal trucks due to high water but could be passable with specialized vehicles. In my opinion, this alternative needs to be fully explored and evaluated to determine the most prudent course of action before including the $31.5 million in the SPP.

**Q. HOW DOES TAMPA ELECTRIC USE ITS TRANSMISSION RIGHT OF WAY?**

A. Electric utilities such as Tampa Electric use transmission right-of-way to maintain a clear distance from vegetation and to maintain clearances to transmission conductors. In order to maintain structures, maintain the right of way (cutting brush and trees), and to inspect lines, utilities will have a means such as a road or access drive to accomplish these tasks. The maintenance of these roads and access points is a core function of an electric utility that owns transmission lines. When the line was originally constructed, large vehicles needed access to install poles and the access roads were established. The utility normally maintains this access into the future. Tampa Electric noted that the deterioration of the transmission access roads was caused by Tampa Electric itself. Specifically, Tampa Electric's hardening activities of replacing transmission poles has adversely impacted bridges.[48] In addition, Tampa Electric noted they made temporary repairs to the bridges

[48] *See* Exhibit DAP-1, p. 49 of 78.

damaged from use over the last several storm seasons.[49] But these temporary repairs now need attention.

**Q. IN YOUR OPINION DOES REPLACEMENT OF BRIDGES AND IMPROVEMENTS TO ACESS ROADS CONSTITUTE ENHANCEMENTS?**

A. No. An electric utility has a duty to maintain their infrastructure including roads. Replacing bridges and re-building roads are not enhancement programs but rather simply maintaining infrastructure at the same status quo.

Storm hardening is about increasing the integrity of system components beyond what is normally required such as replacing a pole with pole stronger than that required by the NESC that will help reduce storm damage and storm damage restoration costs. Storm hardening in this portion of the business means more aggressive vegetation management or more frequent pole inspection. It is not clear why Tampa Electric has not maintained its access roads and bridges. Any reduction in outage times or restoration costs should be measured against a well-maintained infrastructure of roads and bridges. Since Tampa Electric is only bringing the existing status of inadequate or poor-quality roads and bridges to a well-maintained state, there is no reduction in storm restoration costs and no reduction in outage time. These projects to do not meet the two-prong test for Rule 25-6.030 F.A.C., which requires a reduction in restoration costs and a reduction in outage time.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TRANSMISSION ACCESS ENHANCEMENT PROGRAM PROPOSED BY TAMPA ELECTRIC?**

A. I recommend that this proposed program for access bridges and access roads with a combined 10-year budget of $32.4 million be excluded from the Storm Protection Plan.

[49] *See* Exhibit DAP-1, p. 49 of 78.

**Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?**

A. Yes, it does.

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

# KEVIN J. MARA, P.E.

Exec. Vice President & Principal Engineer

## EDUCATION

BS Electrical Engineering, Georgia Institute of Technology, 1982

## PROFESSIONAL MEMBERSHIPS

Institute of Electrical and Electronic Engineers Power Engineering Society – Senior Member

National Electric Safety Code Subcommittee 5 – Alternate Member

Past Member - Insulated Conductor Committee

## PROFESSIONAL REGISTRATIONS

Registered Professional Engineer in Alabama, Arkansas, Georgia, Florida, Idaho, Indiana, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Missouri, North Carolina, Ohio, Oregon, Pennsylvania, South Carolina, South Dakota, Tennessee, Texas, Virginia, Washington, and Wisconsin.

## AREAS OF EXPERTISE

Overhead and Underground Distribution Design, Distribution System Planning, Power System Modeling and Analysis, Training

## DESIGN

Mr. Mara has over 30 years of experience as a distribution engineer. He worked six years at Savannah Electric as a Distribution Engineer and ten years with Southern Engineering Company as a Project Manager. At Savannah Electric, Mr. Mara gained invaluable field experience in the operation, maintenance, and design of transmission and distribution systems. While at Southern Engineering, Mr. Mara performed planning studies, general consulting, underground distribution design, territorial assistance, and training services. Presently, Mr. Mara is a Vice President at GDS Associates, Inc. and serves as the Principal Engineer for GDS Associates' engineering services company known as its trade name Hi-Line Engineering.

***Overhead Distribution System Design***

Mr. Mara is in responsible charge of the design of distribution lines for many different utilities located in a variety of different terrains and loading conditions. Mr. Mara is in responsible charge of the design of over 100 miles of distribution line conversions, upgrades, and line reinsulation each year. Many of these projects include acquisition of right-of-way, obtaining easements, and obtaining permits from various local, state and federal agencies. In addition, Mr. Mara performs inspections at various stages of completion of line construction projects to verify compliance of construction and materials with design specifications and applicable codes and standards.

***Underground Distribution System Design***

Mr. Mara has developed underground specifications for utilities and was an active participant on the Insulated Conductor Committee for IEEE. He has designed underground service to subdivisions, malls, commercial, and industrial areas in various terrains. These designs include concrete-encased ductlines, direct-burial, bridge attachments, long-bores, submarine, and tunneling projects. He has developed overcurrent and overvoltage protection schemes for underground systems for a variety of clients with different operating parameters.

## PLANNING

Mr. Mara has prepared numerous planning studies for electric cooperatives and municipal systems in various parts of the country. The following is a representative list of specific projects:

- Little River Electric Cooperative, SC
  - Long Range Plan
  - Four Construction Work Plans
- Maxwell AFB, AL - Long Range Plan
- Fall River Electric, ID – Long Range Plan
- Chugach Electric, AK - Long Range Plan
- Newberry Electric Cooperative, SC - Construction Work Plan, Long Range Plan
- Lackland AFB, TX - Long Range Plan
- Rio Grande ECI, TX - Construction Work Plan, Long Range Plan
- Northern Virginia Electric Cooperative, VA - Construction Work Plan
- BARC Electric Cooperative - Construction Work Plan
- Dixie Electric Cooperative - Construction Work Plan
- Joe Wheeler Electric Cooperative - Construction Work Plan
- Cullman Electric Cooperative - Long Range Plan, Construction Work Plan

## TRAINING SEMINARS

Mr. Mara has developed engineering training courses on the general subject of distribution power line design. These seminars have become extremely popular with more than 25 seminars being presented annually and with more than 4,000 people having attended seminars presented by Mr. Mara. A 3-week certification program is offered by Hi-Line Engineering in eleven states. The following is a list of the training material developed and/or presented:

- Application and Use of the National Electric Safety Code
- How to Design Service to Large Underground Subdivisions
- Cost-Effective Methods for Reducing Losses/Engineering Economics
- Underground System Design
- Joint-Use Contracts – Anatomy of Joint-Use Contract
- Overhead Structure Design
- Easement Acquisition
- Transformer Sizing and Voltage Drop

***Construction Specifications for Electric Utilities***

Mr. Mara has developed overhead construction specifications including overhead and underground systems for several different utilities. The design included overcurrent protection for padmounted and pole mounted transformers. The following is a representative list of past and present clients:

- Cullman EMC, Alabama
- Blue Ridge EMC, South Carolina
- Buckeye Rural Electric Cooperative, Ohio
- Three Notch EMC, Georgia
- Little River ECI, South Carolina
- Lackland Air Force Base
- Maxwell Air Force Base

## SYSTEM PRIVATIZATION/EVALUATION

- Central Electric Power Cooperative, Columbia, SC
  - 2017 Independent Certification of Transmission Asset Valuation, Silver Bluff to N. Augusts 115kV
  - 2015 Independent Certification of Transmission Asset Valuation, Wadmalaw 115kV
- Choctawhatchee Electric Cooperative, DeFuniak Springs, FL
  - Inventory and valuation of electrical system assets at Eglin AFB prior to 40-year lease to private-sector entity.

## PUBLICATIONS

- Co-author of the NRECA "Simplified Overhead Distribution Staking Manual" including editions 2, 3 and 4.
- Author of "Field Staking Information for Overhead Distribution Lines"
- Author of four chapters of "TVPPA Transmission and Distribution Standards and Specifications"

## TESTIMONIES & DEPOSITIONS

Mr. Mara has testified as an expert at trial or by deposition in the following actions.

- Deposition related to condemnation of property
  Newberry ECI v. Fretwell, 2005
  State of South Carolina

- Testimony in Arbitration regarding territory dispute
  Newberry ECI v. City of Newberry, 2003
  State of South Carolina
  Civil Action No. 2003-CP-36-0277

- Expert Report and Deposition, 2005
  United States of America v. Southern California Edison Company
  Case No CIV F-o1-5167 OWW DLB

- Expert Report and Deposition, 2005
  Contesting a transmission condemnation
  Moore v. South Carolina Electric and Gas Company
  United States District Court of South Carolina
  Case No. 1:05-1509-MBS

- Affidavit October 2007
  FERC Docket No. ER04-1421 and ER04-1422
  Intervene in Open Access Transmission Tariff filed by Dominion Virginia Power

- Affidavit February 26, 2008
  FERC Docket No. ER08-573-000 and ER08-574-000
  Service Agreement between Dominion Virginia Power and WM Renewable Energy, LLC

- Direct Filed Testimony date December 15, 2006
  Before the Public Utility Commission of Texas
  SOAH Docket No 473-06-2536
  PUC Docket No. 32766

- Expert Report and Direct Testimony April 2008
  United States Tax Court
  Docket 25132-06
  Entergy Corporation v. Commissioner Internal Revenue

- Direct Testimony September 17, 2009
  Public Service Commission of the District of Columbia
  Formal Case 1076
  Reliability Issues

- Filed Testimony regarding the prudency of hurricane restoration costs on behalf of the City of Houston, TX, 2009
  Cozen O'Connor P.C.
  TX PUC Docket No. 32093 – Hurricane Restoration Costs

- Technical Assistance and Filed Comments regarding line losses and distributive generation interconnection issues, 2011
  Office of the Ohio Consumer's Counsel
  OCC Contract 1107, OBM PO# 938 for Energy Efficiency T & D

- Technical Assistance, Filed Comments, and Recommendations evaluating Pepco's response to Commission Order 15941 concerning worst reliable feeders in the District of Columbia.
  2011, 2012 Office of the People's Counsel of the District of Columbia
  Formal Case No. 766

- Technical Assistance, Filed Comments, and Recommendations on proposed rulemaking by the District of Columbia PSC amending the Electric Quality of Service Standards (EQSS), 2011.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 766

- Yearly Technical Review, Filed Comments, and Recommendations evaluating Pepco's Annual Consolidated Report for 2011 through 2021.
  Office of the People's Counsel of the District of Columbia
  Formal Case Nos. 766; 766-ACR; PEPACR(YEAR)

- Technical Evaluation, Filed Comments, and Recommendations evaluating Pepco's response to a major service outage occurring May 31, 2011. (2011)
  Office of the People's Counsel of the District of Columbia
  Formal Case Nos. 766 and 1062

- Technical Assistance, Filed Comments, and Recommendations evaluating Pepco's response to Commission Order 164261 concerning worst reliable neighborhoods in the District of Columbia, 2011.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 766

- Technical Review, Filed Comments, and Recommendations on Pepco's Incident Response Plan (IRP) and Crisis Management Plan (CMP), 2011.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 766

- Technical Assistance, Filed Comments, and Recommendations assessing Pepco's Vegetation Management Program and trim cycle in response to Oder 16830, 2012.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 766
- Technical Review, Filed Comments, and Recommendations on Pepco's Secondary Splice Pilot Program in response to Order 16426, 2012.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 766 and 991
- Technical Review, Filed Comments, and Recommendations on Pepco's Major Storm Outage Plan (MSO), 2012 - active.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 766
- Technical Assistance and Direct Filed Testimony for fully litigated rate case, 2011-2012.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1087 – Pepco 2011 Rate Case. Hearing transcript date: February 12, 2012.
- Evaluation of and Filed Comments on Pepco's Storm Response, 2012.
  Office of the People's Counsel of the District of Columbia
  Storm Dockets SO-02, 03, and 04-E-2012
- Technical Assistance and Direct Filed Testimony for fully litigated rate case, 2013 - 2014.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1103 – Pepco 2013 Rate Case. Hearing transcript date: November 6, 2013.
- Evaluation of and Filed Comments on Prudency of 2011 and 2012 Storm Costs, 2013 – 2014.
  State of New Jersey Division of Rate Counsel
  BPU Docket No. AX13030196 and EO13070611
- Technical Assistance and Direct Filed Testimony for DTE Acquisition of Detroit Public Lighting Department, 2013 – 2014.
  Office of the State of Michigan Attorney General
  Docket U-17437
- Evaluation of and Filed Comments on the Siemens Management Audit of Pepco System Reliability and the Liberty Management Audit, 2014.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1076
- Expert witness for personal injury case, District of Columbia
  Koontz, McKenney, Johnson, DePaolis & Lightfoot LLP
  Ghafoorian v Pepco 2013 - 2016
  Plaintive expert assistance regarding electric utility design. operation of distribution systems and overcurrent protection systems.
- Technical Assistance and Direct Filed Testimony in the Matter of the Application for approval of the Triennial Underground Infrastructure Improvement Projects Plan, 2014 – 2017.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1116
- Technical Assistance and Direct Filed Testimony in the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity, LLC, 2014 – 2016.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1119. Hearing transcript date: April 21, 2015.

- Technical Assistance to Inform and advise the OPC in the matter of the investigation into modernizing the energy delivery system for increased sustainability. 2015 - active
  Office of the People's Counsel of the District of Columbia
  Formal Case No 1130.
- Technical Assistance and Direct Filed Testimony in the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc., 2014 – 2016.
  State of Maryland and the Maryland Energy Administration
  Case No. 9361.
- Technical Assistance and Direct Filed Testimony for fully litigated rate case, 2015 – 2016.
  State of Oklahoma Office of the Attorney General
  Cause No. PUD 201500273 - OG&E 2016 Rate Case. Hearing transcript date: May 17, 2016.
- Technical Assistance and Filed Comments on Notice of Inquiry, The Commission's Investigation into Electricity Quality of Service Standards and Reliability Performance, 2016 - 2018.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1076; RM36-2016-01-E.
- Technical Assistance and Direct Filed Testimony for fully litigated rate case, 2016 - 2017.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1139 – Pepco 2016 Rate Case. Hearing transcript date: March 21, 2017.
- Technical Assistance in the Matter of the Application for approval of the Biennial Underground Infrastructure Improvement Projects Plan, 2017.- active
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1145
- Technical Assistance to Inform and advise the OPC Regarding Pepco's Capital Grid Project, 2017 - active.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1144. Confidential Comments and Confidential Affidavit filed November 29, 2017.
- Expert witness for personal injury case Mecklenburg County, NC
  Tin, Fulton, Walker & Owen, PLLC
  Norton v Duke, Witness testimony December 1, 2017
- Technical assistance and pre-filed Direct Testimony on behalf of the Joint Municipal Intervenors in a rate case before the Indiana Utility Regulatory Commission.
  Cause No. 44967. Testimony filed November 7, 2017.
- Prefiled Direct Testimony and Prefiled Surrebuttal Testimony on behalf of the Vermont Department of Public Service in a case before the State of Vermont Public Utility Commission, Tariff Filing of Green Mountain Power Corp.
  Case No. 18-0974-TF. Direct Testimony Filed August 10, 2018. Surrebuttal Testimony Filed October 8, 2018.
- Technical assistance and pre-filed Direct Testimony on behalf of McCord Development, Inc. and Generation Park Management District against CenterPoint Energy Houston Electric, LLC in a case before the State Office of Administrative Hearings of Texas.
  TX PUC Docket No. 48583. Direct Testimony filed April 5, 2019.

- Technical Assistance, Direct Filed Testimony, Rebuttal Testimony, Surrebuttal Testimony, and Supplemental Testimony for fully litigated rate case, 2019 – active.
  Office of the People's Counsel of the District of Columbia
  Formal Case No. 1156 – Pepco 2019 Rate Case. Direct Testimony Filed March 6, 2020. Rebuttal Testimony Filed April 8, 2020. Surrebuttal Testimony Filed June 1, 2020. Supplemental Testimony filed July 27, 2020.

- Technical assistance and pre-filed Direct Testimony on behalf of The State of Florida Public Counsel for Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C.
  Docket No. 20200071-EI.
  - Gulf Power SPP. Direct Testimony filed May 26, 2020.
  - Florida Power& Light Company SPP. Direct Testimony filed May 28, 2020.

- Prefiled Direct Testimony on behalf of the Vermont Department of Public Service in a case before the State of Vermont Public Utility Commission, Petition of Green Mountain Power for approval of its climate Plan pursuant to the Multi-Year Regulation Plan.
  Case No. 20-0276-PET. Direct Testimony Filed May 29, 2020.

- Technical assistance and Filed Comments on behalf of East Texas Electric Cooperative on a Proposal for Publication by the Public Utility Commission of Texas on Project 51841 Review of 16 TAC § 25.53 Relating to Electric Service Emergency Operations Plans.
  Project 51841. Comments filed January 4, 2022.

- Technical assistance, filed affidavit and direct testimony on behalf of Bloomfield, NM in an action concerning Bloomfield's exercise of its right to acquire from Farmington the electric utility system serving Bloomfield.
  Bloomfield v Farmington, NM. State of New Mexico, County of San Juan, Eleventh Judicial District Court Action No. D-1116-CV-1959-07581.

- Technical assistance and pre-filed Direct Testimony on behalf of Sawnee EMC in a territorial dispute with Electrify America.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20220048-EI**
**OPC'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 50**
**BATES PAGE: 66**
**FILED: MAY 18, 2022**

**50.** What role, if any, does customer rate impact have on your determination of the total level of (1) capital (2) O&M expense contained in each of the first three years of your pending SPP? Please identify each document discussing, analyzing, and describing such determination in each year.

**A.** As stated above, customer rate impacts are examined as an end result and is not used to determine the total level, either down or up, of (1) capital (2) O&M expense contained in each of the first three years of the company's 2022-2031 SPP.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20220048-EI**
**OPC'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 39**
**BATES PAGE: 55**
**FILED: MAY 18, 2022**

**39.** In determining how to deploy capital investment in your pending SPP please describe the steps that were taken to consider customer rate impacts. As a part of any description you undertook, please describe the role that customer rate impacts play compared to your investor-driven financial goals such as the increasing adjusted earnings per share expectations at your publicly traded corporate entity level and yearly expected growth in dividend per share.

**A.** Tampa Electric evaluated customer rate impacts at the Plan level, as opposed to the individual Program or Project level. This means that specific rate impacts were calculated after the company decided on an overall level of investment for the Plan. It is important to note, however, that potential customer impacts were given significant weight in setting this proposed investment level. The company asked 1898 & Co. to quantify the benefits associated with several proposed levels of investment. This analysis confirmed that customers would receive net benefits from their investment and that the company's proposed investment level is set before the point of diminishing returns where additional investment only provides a minor increase in benefits. Once the investment level was set, and its benefits were confirmed by 1898's analysis, the company calculated the specific bill impact associated with that investment level. The company determined that this expected bill impact was reasonable in comparison with the projected benefits of the investment. The company's financial goals at the publicly traded entity level were not included in the analysis performed by Tampa Electric or 1898 to develop the plan.

Customer rate impacts from the SPP are not included in any comparison to the company's investor-driven financial goals such as the increasing adjusted earnings per share expectations at your publicly traded corporate entity level and yearly expected growth in dividend per share.

A Chronology of Major Events Affecting the
National Flood Insurance Program

December 2005

Completed for the Federal Emergency Management Agency Under Contract Number 282-98-0029

The American Institutes for Research
The Pacific Institute for Research and Evaluation
Deloitte & Touche LLP

Acronyms
CRS
FEMA
FHBM
FIA
FIMA
FIRM
FY
GAO
NFIP
PL
SFHA
TVA
USGS
WYO

Community Rating System
Federal Emergency Management Agency
Flood Hazard Boundary Map
Federal Insurance Administration
Flood Insurance and Mitigation Administration
Flood Insurance Rate Map
Fiscal year
General Accounting Office
National Flood Insurance Program
Public Law
Special Flood Hazard Area
Tennessee Valley Authority
United States Geological Survey
Write Your Own

Please inform Marion Chastain (mchastain@air.org) of all errors and significant omissions.

Date

1824

In Gibbons v. Ogden, the U.S. Supreme Court construes the Constitution's commerce clause (Article I, Section 8) to permit the federal government to finance and construct river improvements. Within two months, Congress appropriates funds and authorizes the Corps of Engineers to remove certain navigation obstructions from the Ohio and Mississippi Rivers.

1849-50

The Swamp Land Acts of 1849 and 1850 transfer swamp and overflow land from federal control to most state governments along the lower Mississippi River on the condition that the states use revenue from the land sales to build levees and drainage channels. The Acts require no federal funds.

1853

Charles S. Ellet, Jr., a leading civil engineer, produces a congressionally mandated report on the Ohio and Mississippi Rivers, insisting that the flood problem is growing as cultivation increases. He suggests enlarging natural river outlets, constructing higher and stronger levees, and building a system of headwaters reservoirs on the Mississippi River and its tributaries. Most engineers of the period disagree.

1861

In a Report upon the Physics and Hydraulics of the Mississippi River, Captain Andrew A. Humphreys, Corps of Topographical Engineers, and Lieutenant Henry L. Abbott support the completion of the existing levee system and exclude alternative flood controls, partly for economic reasons. The emphasis on levees represents the primary focus of U.S. policy on flood control well into the 20th century.

1866

Captain Humphreys becomes Chief of Engineers of the U.S. Army and labors to quash opposition to the “levees-only” policy he advocates.

1879

Congress creates the Mississippi River Commission and gives it authority to survey the Mississippi and its tributaries, formulate plans for navigation and flood control, and report on the practicability and costs of the various alternative courses of action.

By 1890

The entire 700-mile, lower Mississippi Valley, from St. Louis to the Gulf of Mexico, is divided into state and locally organized levee districts.

1891

W. J. McGee, in “The Floodplains of Rivers,” published in Forum, XI, states that “as population has increased, men have not only failed to devise means for suppressing or for escaping this evil [flood], but have a singular shortsightedness, rushed into its chosen paths.”

1913

A flood in the Ohio River Valley kills 415 people and causes about $200 million in property loss. The flood spurs public interest in flood control, leading to the creation of basin-wide levee associations and other lobbying groups.

1916

The U.S. House of Representatives’ Committee on Flood Control is created. The committee becomes a forum for congressional proponents of flood control.

1917

A Flood Control Act (PL 64-367) is approved. Congress appropriates $45 million for a long-range and comprehensive program of flood control for the lower Mississippi and Sacramento Rivers. In doing so, Congress accepts federal responsibility for flood control. The Act includes a requirement for local financial contributions in flood-control legislation and authorizes the Corps of Engineers to undertake examinations and surveys for flood-control improvements and to provide information regarding the relation of flood control to navigation, waterpower, and other uses. The Act establishes important precedents and frameworks for the Flood Control Act of 1936 (see 7/1936).

1927

The Great Mississippi River Flood shows the limits of Humphreys’ “levees-only" policy. The death toll is 246 but may have reached 500, more than 700,000 people are homeless, 150 Red Cross camps care for more than 325,000 refugees, and property damage exceeds $236 million. Nearly 13 million acres of land are flooded.

5/1928

Through a new Flood Control Act (PL 70-391), Congress adopts a flood-control plan that abandons the levees-only approach. The Act commits the federal government to pay for the construction of protective measures. The non-federal contribution is to provide rights-of-ways for the levees along the main stem. Levee districts and state governments will maintain the levees. Expenditures of $325 million are authorized.

1929

The private insurance industry abandons the coverage of flood losses.

5/1933

Congress creates the Tennessee Valley Authority (TVA)through PL 73-17 as a government corporation armed with the power to plan, build, and operate multipurpose development projects for water resources within the 40,000 square miles of the Tennessee River basin.

1933

In response to a major earthquake in California, and contrary to past traditions, Congress enacts legislation to provide direct assistance to private citizens suffering disaster damage by issuing federal loans through the Reconstruction Finance Corporation.

4/1934

In response to several disasters that befell communities in disparate parts of the country, Congress enacts PL 73-160, which makes $5 million in loans available to victims of all natural disasters, including floods.

7/1936

The Flood Control Act of 1936 (PL 74-738) provides for the construction of approximately 250 projects using funds for work relief. Congress appropriates $310 million to initiate construction and $10 million to complete examinations and surveys. The Act establishes a two-pronged attack on the problem of reducing flood damages: the Department of Agriculture will develop plans to reduce runoff and retain more rainfall and the Corps of Engineers will develop engineering plans for downstream projects. The Act represents the initial development of a national flood-control program.

1938

Harlan H. Barrows, one of 12 members on the Water Resources Committee (WRC), submits a report to the WRC President, expressing his views that good planning requires linking land and water use. A report submitted by the Ohio-Lower Mississippi Regulation Subcommittee, which Barrows chairs, states that, "if it would cost more to build reservoir storage than to prevent floodplain encroachment, all relevant factors considered, the latter procedure would appear to be the best solution."

1938

President Franklin Roosevelt forwards to the Water Resources Committee a Corps of Engineers' document calling for the construction of 81 reservoirs in the Ohio and Mississippi River basins. Barrows expresses concern that further studies are needed. The need for more studies temporarily ends further construction proposals.

1942

Gilbert White finishes Human Adjustment to Floods: A Geographic Approach to the Flood Problem in the United States. He advocates, "adjusting human occupancy to the floodplain, and at the same time, of applying feasible and practicable measures for minimizing the detrimental impacts of floods." He characterizes the prevailing national policy as "essentially one of protecting the occupants of floodplains against floods, of aiding them when they suffer flood losses, and of encouraging more intensive use of floodplains."

9/1950

The Disaster Relief Act of 1950 (PL 81-875) provides "an orderly and continuing means of assistance by the Federal Government to States and local governments in carrying out their responsibilities to alleviate suffering and damage resulting from major disasters," including floods. State governments must formally request the president to declare a major disaster. If granted, the federal government will then provide disaster assistance "to supplement the efforts and available resources of states and local governments in alleviating the disaster." The law creates the first permanent system for disaster relief without the need for congressional action.

1950

An internal report from the TVA, Major Flood Problems in the Tennessee River Basin, notes that many communities have flood problems but because of insufficient development in flood-prone areas, flood-control projects cannot be justified. Gordon Clapp, Chairman of the TVA's Board, responds, "What should TVA do, wait for development of the floodplains so that a flood control project could be justified?" He recommends circulating the report to solicit other reactions, particularly from the Division of Regional Studies.

After reviewing the report, Aldred J. Gray, director of the Division of Regional Studies, and a proponent of White's concepts, proposes a different approach to the problem. TVA and state representatives will join in a technical appraisal of the possible application of flood data to planning programs. The joint appraisal will include research into the types and forms of flood information needed by state and local planning programs and how such data can be applied to community planning, land-use controls, and capital improvement programs. During its early work in this area, TVA coins the term "floodplain management."

8/1951

Following massive flooding in Kansas and Missouri that causes more than $870 million in damage, President Harry Truman recommends the creation of a "national system of flood disaster insurance, similar to the war damage insurance of World War II." In Truman's words: "The lack of a national system of flood disaster insurance is now a major gap in the means by which a man can make his home, his farm, or his business secure against events beyond his control." Truman proposes a system of flood insurance based on private insurance with re-insurance by the federal government.

1/1952

President Truman calls for the enactment of legislation to establish a federal flood insurance program and recommends that $50 million be appropriated to create a flood insurance fund.

5/1952

President Truman submits proposed legislation to Congress to establish a national system of flood-disaster insurance. The proposed legislation would establish a maximum amount of insurance of $25,000; establish rates to cover all expenses, including a proper reserve for losses; and authorize federal agencies that make or guarantee loans to require borrowers to purchase flood insurance where it is available.

1953

The TVA embarks on a pioneering cooperative program to tackle local flood problems. In cooperation with each of the states in the Tennessee River's watershed, they prepare an initial list of 150 communities with significant flood problems and agree on an order for undertaking studies to identify flood hazards. Communities having the most urgent need can request a study of their flood problems from the TVA, which will fund the process. This offer, however, does not meet universal acceptance.

Circumstances surrounding these studies significantly retard the early progress of TVA's assistance program for floodplain management. To solve this impasse, two hypothetical floods are computed: the "maximum probable" and the "regional." The TVA uses the maximum probable flood to design flood-control works. This leads to development of a model by the TVA's engineers that is large enough to use in planning and that state planners believe to be fair and reasonable. The model is based on actual flood occurrences near the studied streams. The TVA's flood-hazard information reports developed during this period do not change substantially until the mid-1970s.

8/1954

The Watershed Protection and Flood Prevention Act (PL 83-566) authorizes flood-protection structures in upstream watersheds (defined as smaller than 250,000 acres). The Act also authorizes the U.S. Department of Agriculture's Soil Conservation Service (now the Natural Resources Conservation Service) to participate in comprehensive watershed management projects in cooperation with states and their subdivisions.

1954

Walter B. Langbein, an employee of the U.S. Geological Survey (USGS), designs a report format consisting of a map with pertinent text in the margins. This report becomes the Hydrologic Investigations Atlas No. 1 (HA-1). This successful format is often repeated in following years.

6/1955

PL 84-71, the Coastal and Tidal Areas – Survey – Damages Act, requires the Corps of Engineers to conduct a study of the behavior and frequency of hurricanes on the eastern and southern coasts and to assess "possible means of preventing loss of human lives and damages to property…."

1955

William G. Hoyt and Walter B. Langbein, two noted hydrologists, endorse White's concepts in their book, Floods, which traces the evolution of public flood-control policies, describes current problems, and suggests desirable changes. White characterizes their work as the first to synthesize the scientific information about floods.

1/1956

In a budget message to Congress, President Dwight Eisenhower recommends legislation to establish, on an experimental basis, an "indemnity and reinsurance program, under which the financial burden resulting from flood damage would be carried jointly by the individuals protected, the States, and the Federal Government." He requests $100 million to start the program.

8/1956

The Federal Flood Insurance Act of 1956 (PL 84-1016) directs the Housing and Home Finance Agency to establish a program of federal insurance and re-insurance against the risks of losses resulting from floods and tidal disasters. The program is intended to provide up to $10,000 in insurance per dwelling and to encourage private companies to provide coverage for risks above that amount. The cost of coverage for policyholders will be the same regardless of their location.

9/1956

The Housing and Home Finance Agency creates the Federal Flood Indemnity Administration to carry out tasks set forth in the Federal Flood Insurance Act of 1956.

1956

A study for the American Insurance Association on floods and flood losses strengthens insurers' conviction that flood insurance is not commercially feasible.

6/1957

In the absence of technical studies to determine the costs of starting a federal program for flood insurance, Congress does not appropriate any funds for the Federal Flood Indemnity Administration. As a consequence, the administration ceases to exist.

11/1958

A study by Gilbert White and his colleagues, Changes in Urban Occupancy of Flood Plains in the United States, reveals what had happened during the previous two decades. With land-use pressures and few incentives to stay out of potential flood zones, occupancy in these zones is increasing, even in urban areas where population is declining. Federal incentives are creating a new perception that if a serious flood hazard develops, the federal government will deal with it.

11/1958

In Regulating Flood Plain Development, Francis C. Murphy notes that no more than eight communities had enacted floodplain zoning before 1955. By 1958, 49 communities had ordinances. To convince others of the need for more regulations, he argues that regulating development on the floodplain is a necessary and practicable way to reduce the drain of both floods and protective measures on the national economy. He observes that governments are reluctant to enact land-use management practices because they have no flood maps or other data that indicate the extent and character of local flooding.

12/1958

The growing loss of property and the cost of flood damage from several major hurricanes and floods convinces the Council of State Governments to recommend that one federal agency be directed by Congress to cooperate with other federal agencies and state governments to prepare reports providing data on the magnitude and frequency of floods in flood-prone areas.

1958

By this time, only seven states have enacted and are enforcing floodplain management regulations, principally for narrow-channel encroachment areas.

1958

The Corps of Engineers prepares draft legislation providing for the systematic collection and dissemination of flood data as a new Corps' mission.

8/1959

The TVA submits a report to Congress proposing a program to reduce damages associated with floods (A Program for Reducing the National Flood Damage Potential: Memorandum of the Chairman to Members of the Committee on Public Works, U.S. Senate, 86th Cong., 1st Sess., 31 Aug. 1959). In its letter of transmittal, the TVA states that it “believes that local communities have the responsibility to guide their growth so that their future development will be kept out of the path of floodwaters. With the States and communities of the Tennessee Valley, TVA has developed a means of putting this proposition into action.” Floodplain management formally enters the federal agenda with the report’s submission.

1959

Floods at Topeka, Kansas (HA-14) is published, the first in a series flood atlases.

1959

The USGS adopts flood-inundation maps as a means to depict information about floods. Publishing such maps, which delineate boundaries of inundated areas, provide profiles of water surfaces, and show flood-frequency relations, becomes a standard means of reporting about floods.

7/1960

Amendments to the Flood Control Act contained in PL 86-645 authorize the Corps of Engineers to compile and disseminate information on floods and flood damages at the request of a state or responsible local agency. As a result of the Act, the Corps of Engineers establishes a Flood Plain Management Service and thus promotes the use of nonstructural measures for dealing with floods.

1960

John R. Sheaffer publishes the first comprehensive study on floodproofing, Flood Proofing: An Element in a Flood Damage Reduction Program.

1/1961

The U.S. Senate’s Select Committee on National Water Resources issues a report on floodplain management. The report becomes the means through which the concepts of floodplain management are officially recommended. The report calls for major efforts in five categories. Among these are recommendations that the federal government delineate flood-hazard areas and encourage enactment of land-use regulations for floodplains.

1961

A flood atlas, Floods at Boulder, Colorado (HA-41), summarizes the results of a study of Boulder Creek in which areas inundated by floods of several frequencies were constructed synthetically from past records and physical surveys of the floodplain.

1962

The State of Washington enacts a law that provides for the establishment of flood-control zones when data are available.

8/1964

Following the “Good Friday” earthquake and subsequent seismic waves in Alaska in March, Congress ushers in the direct subsidy, or grant, as a federal disaster relief policy through PL 88-451 (the 1964 Amendments to the Alaska Omnibus Act).

1964

Gilbert White's Choice of Adjustment to Floods, based on a field study in La-Follette, Tennessee, analyzes existing methods and practices and addresses alternative means of dealing with flood problems by occupants, communities, and federal agencies. His study aids the ongoing discussions and debates concerning the paths that should be taken and the ways of canvassing the whole range of alternatives for achieving desirable land use.

7/1965

The Water Resources Planning Act of 1965 (PL 89-90) creates the Water Resources Council (WRC), an independent agency composed of the secretaries of federal agencies with responsibilities for water resource management. Its purpose will be to study, coordinate, and review water and related land resource requirements, policies, and plans.

11/1965

The Southeast Hurricane Disaster Relief Act (PL 89-339) is passed in response to Hurricane Betsy and other hurricanes, which devastated the south in 1963 and 1964. The Act mandates the Secretary of the Department of Housing and Urban Development to "undertake an immediate study of alternative programs which could be established to help provide financial assistance to those suffering property losses in floods and other natural disasters, including alternative methods of Federal disaster insurance…."

1965

The TVA has prepared 92 reports on floodplains covering 112 communities. Forty-three of these communities have officially adopted floodplain regulations in their zoning ordinances, subdivision regulations, or both.

1965

California encourages "local levels of government to plan land use regulations to accomplish floodplain management and to provide state assistance and guidance as appropriate."

1965

The Bureau of the Budget's Task Force on Federal Flood Control Policy is established. It represents a significant step toward a unified federal policy for managing the nation's floodplains.

1965

The National Association of Insurance Commissioners' Flood and Hurricane Committee and National All-Industry Flood Insurance Committee are created.

8/1966

The Task Force on Federal Flood Control Policy, with Gilbert White as chair, issues A Unified National Program for Managing Flood Losses (U.S. House of Representatives, House Document 465, 89th Cong., 2nd Sess.). The report examines ways in which the federal government can decrease flood losses without large expenditures for flood control. It is supportive of state and local regulation of the use of lands exposed to flood hazard.

Concluding that federally subsidized insurance will provide an important incentive to local communities to participate in a flood insurance program, the report recommends a system of structural and nonstructural approaches to flood control. In addition, the report recommends that a practicable national program of flood insurance be established and calls for an integrated program to manage losses from floods that would involve federal, state, and local governments and the private sector. The report also recommends a limited, experimental test of a national flood insurance program before nationwide implementation. The report warns, however, that "if misapplied an insurance program could aggravate rather than ameliorate the flood program." The report estimates that subsidies for existing high-risk properties will be required for approximately 25 years.

8/1966

Executive Order No. 11296, Evaluation of Flood Hazard in Locating Federally Owned or Financed Buildings, Roads, and Other Facilities, and in Disposing of Federal Lands and Properties, is issued. It directs federal agencies to provide leadership in encouraging an effort to prevent unnecessary use of the country's floodplains and to lessen the risk of flood losses; evaluate flood hazards; and develop procedures to ensure that flood-hazard evaluations are conducted before initiating federally financed or supported actions in floodplains.

8/1966

President Lyndon Johnson submits to Congress a feasibility study of a flood insurance program conducted by the Secretary of the Department of Housing and Urban Development and mandated by the Southeast Hurricane Disaster Relief Act (see 11/1965). The study, Insurance and Other Programs for Financial Assistance to Flood Victims, concludes that flood insurance is feasible and will promote the public interest. Flood insurance is viewed both as a means to help individuals bear the risks of flood damage and, equally, as a means to discourage unwise occupancy of floodplains. The report envisions a program of essentially private character but with continued large-scale participation of the federal government. The approach recommended would include subsidies of premiums for existing properties in high-risk areas. To encourage widespread purchase of flood insurance, the report further recommends that all "lending institutions entrusted with savings or deposits and under any form of Federal supervision…shall require in high-risk areas flood insurance at unsubsidized rates on all new mortgages based on new residences…."

1966

New Jersey authorizes a state agency to delineate and mark flood-hazard areas to identify reasonable and proper use of these areas according to their relative flood risk and to develop and disseminate other information on floodplains.

1966

Wisconsin enacts a comprehensive act providing for the adoption of a reasonable and effective zoning ordinance for floodplains by every county, city, and village before January 1, 1968.

5/1967

The Corps of Engineers publishes Guidelines for Reducing Flood Damages.

6/1967

The USGS publishes a 19-volume study of the magnitude and frequency of floods in the United States.

7/1967

Representatives of 26 federal agencies adopt a draft of Proposed Flood Hazard Evaluation Guidelines for Federal Executive Agencies. These guidelines deal with methodologies and standards to be used in developing information about flood hazards, including delineation of the floodplain, elevations that floods of various magnitudes would reach, flood velocities, and the probability of floods of various magnitudes. Use of the 100-year flood as the base standard is first advocated. After receiving these guidelines, the Bureau of Budget asks the Water Resources Council to conduct a more detailed review, revise where appropriate, and issue the Guidelines (see 9/1969).

12/1967

The Water Resources Council (WRC) publishes Bulletin No. 15, A Uniform Technique for Determining Flood Flow Frequencies, a study prepared by its Hydrology Committee to determine the best methods to analyze the frequency of floods. The WRC adopts the techniques presented in the bulletin for use in all federal planning involving water and related land resources and recommends their use by state and local governments and private organizations.

8/1968

The Corps of Engineers, which has been mapping and identifying flood-prone areas since 1962, estimates that there are about 5,000 flood-prone communities in the United States.

8/1968

The National Flood Insurance Act of 1968 (Title XII of the Housing and Urban Development Act of 1968 [PL 90-448]) creates the National Flood Insurance Program (NFIP) and the Federal Insurance Administration (FIA) within the Department of Housing and Urban Development to provide flood insurance in communities that voluntarily adopt and enforce floodplain management ordinances by June 30, 1970, that meet minimum NFIP requirements.

Residents will be eligible for flood insurance after the NFIP identifies local flood-hazard areas and establishes actuarial rates. Occupants of structures in floodplains will have their premiums subsidized. Structures built in floodplains after the Act's passage will pay actuarially based premiums.

Section 1360 of the 1968 Act authorizes the Secretary of the Department of Housing and Urban Development to consult with, receive information from, and enter into any agreements or other arrangements with heads of other federal departments or enter into contracts with any persons or private firms in order that he may identify and publish information with respect to all floodplain areas, including coastal areas located in the United States that have special flood hazards, within five years following the date of the Act's approval.

Section 1361 authorizes the NFIP to develop criteria that states and communities can apply to deter development in flood-prone areas.

The Act also requires that flood-risk zones be established in all flood-prone areas and that rates of probable flood-caused losses be estimated for the various flood-risk zones for each of these areas within 15 years (i.e., by August 1,1983) following enactment.

Section 1302 (c) requires that "the objectives of a flood insurance program should be integrally related to a unified national program for floodplain management," and directs that "… the President should transmit to Congress for its consideration any further proposals for such a unified program." The Bureau of the Budget assigns responsibility to prepare such a proposal to the Water Resources Council.

Section 1314 denies disaster relief to persons who could have purchased flood insurance for a year or more and did not do so.

The Act creates the National Flood Insurance Fund in the Department of the Treasury. Premiums from the sales of flood insurance will be deposited into the fund, and losses, operating costs, and administrative expenses are paid out of the fund, which will operate without fiscal-year limitations. The NFIP is authorized to borrow up to $1 billion from the Department of the Treasury to cover losses that exceeds the program's revenues. Presidential approval is required for loans exceeding $500 million.

8/1968

PL 90-448, the Urban Property Protection and Reinsurance Act of 1968 (part of the Housing and Urban Development Act of 1968), establishes the position of Federal Insurance Administrator within the Department of Housing and Urban Development.

12/1968

The Secretary of the Department of Housing and Urban Development delegates authority for administering the NFIP to FIA.

12/1968

The industry's flood insurance pool, the National Flood Insurers Association (NFIA), authorized in accordance with sections 1331 and 1332 of the National Flood Insurance Act, is created. Administered by the Insurance Services Office, membership in the NFIA is open to all qualified companies licensed to write property insurance under the laws of any state. The companies will sell and service policies written as part of the NFIP.

1968

The USGS begins to outline approximate floodplain boundaries on topographic maps. The USGS agrees to assist FIA in its mapping efforts by preparing detailed flood insurance studies, restudies, and limited detailed studies (completed when comprehensive studies cannot be justified).

1968

The Corps of Engineers creates a Floodplain Management Services Branch in the Planning Division of the Office of Chief of Engineers.

1/1969

The National Flood Insurance Program begins its operations.

2/1969

HUD's Federal Insurance Administration (FIA) publishes a proposed rule containing the first floodplain management criteria for the NFIP. The proposed rule does not mention the 100-year flood standard or any other flood standard.

5/1969

George K. Bernstein becomes the first Federal Insurance Administrator.

6/1969

The Final Rule regarding floodplain management criteria defines special flood hazard areas as the 100-year floodplain for mapping purposes. Communities are required to "take into account the relation between first floor elevations and the anticipated level of the 100-year flood" in developing floodplain management measures.

6/1969

The Department of Housing and Urban Development and the National Flood Insurers Association (NFIA) sign an agreement for the marketing of flood insurance policies and the adjustment of claims. Under the agreement, the NFIA will appoint a servicing company, generally on a statewide basis, to disseminate information on the insurance aspects of the program both to the public and to insurance agents, to process all insurance policies, and to handle the adjustment of claims for loss payments.

The first flood insurance policies are sold.

6-8/1969

The first communities joining the NFIP become eligible for participation using data from the USGS and Corps of Engineers. Metairie, Louisiana, and Fairbanks, Alaska, enter the NFIP on June 25. Alexandria, Virginia, enters on August 22 with Flood Insurance Rate Maps (FIRMs) based on Corps of Engineers' Floodplain Information Reports. Biloxi, Mississippi, and other communities along the Mississippi River become eligible for program participation at the end of 1969 with studies using data from the USGS. A FIRM is an official map of a community on which both the special hazard areas and the risk premium zones applicable to the community are delineated.

8/1969

Hurricane Camille strikes the Gulf Coast. In parts of Mississippi, water is 24 feet above the normal high tide. More than 250 people die because of the storm, which one retrospective analysis suggests may be "the most significant economic weather event in the world's history." No communities that suffer from flooding are covered by the NFIP.

8/1969

Congress approves the National Environmental Policy Act (NEPA) (PL 91-190), which declares environmental quality as a national goal and establishes a procedure to assess the environmental impacts of proposed federal projects and programs that could significantly affect the environment. NEPA lays the legislative and administrative foundation for evaluating environmental resources associated with river corridors and coastal zones.

9/1969

The Water Resources Council publishes a revised version of Flood Hazard Evaluation Guidelines for Federal Executive Agencies for federal agencies, states, and consultants to review through experimental use. The revised guidelines define the floodway as that portion of the floodplain needed to accommodate passage of the 1-percent annual chance flood without increasing the level of the flood by more than one foot.

12/1969

Section 408 of the Housing and Urban Development Act of 1969 (PL 91-152) provides for an "emergency program" (in contrast to the original or "regular" program) whereby limited amounts of subsidized insurance can be made available in participating communities before completion of detailed flood insurance studies and FIRMs (see 6-8/1969).

FIA will provide communities in the emergency program with Flood Hazard Boundary Maps (FHBMs). Such maps, which are based on available information, outline the areas estimated to be within the 100-year floodplain. FHBMs are less detailed than FIRMs, which are based on comprehensive flood insurance studies. A community will be eligible for the regular program when a FIRM is completed for that community.

The emergency program does not affect the requirement that such communities must adopt adequate floodplain management regulations. The law also postpones until December 31, 1971, the deadline for communities to enact measures for floodplain management that are necessary for continued participation in the NFIP and revises the definition of a flood to include inundation from mudslides. The deadline is subsequently extended several times.

12/1969

In an interpretation of congressional intent, FIA decides to use data provided by a local community to identify and map flood-prone areas so the community can participate in the emergency program. Thus, it becomes an accepted practice for FIA to issue a map delineating flood-hazard areas of a community if sufficient flood data exist. If sufficient flood data do not exist and there is adequate information to indicate a potential for destructive floods in a community, a map is issued that shows the entire community to be flood prone.

12/1969

Only four communities have joined the NFIP, and only 16 policies have been sold.

1/1970

Four communities are in the “regular program,” 16 flood insurance policies have been sold, and $392,000 of coverage is in force.

3/1970

NFIP regulations are published in the Federal Register. The regulations contain the first criteria for floodplain management. These criteria are general in nature and do not contain specific standards, as do current criteria. To maintain eligibility, participating communities must adopt measures for floodplain management compliant with these regulations no later than December 31, 1971.

12/1971

Almost 920 communities are eligible for coverage under the NFIP. More than 87,000 flood insurance policies are in effect with coverage totaling $1.4 billion.

1971

The Water Resources Council publishes the first volume of Regulation of Flood Hazard Areas to Reduce Flood Losses, which reports on a study that used regulations to guide adjustment of individual land uses to meet flood threats and avoid flood damages. The Council concludes that “the precise manner in which Federal flood insurance and land use controls will be integrated is unclear” and further notes that flood insurance “will not be an adequate substitute for guiding new development or regulating existing development in flood hazard areas.” The report includes draft statutes and local ordinances for regulation of land uses in riverine and coastal flood hazard areas.

5/1972

The Water Resources Council, after receiving comments on their use (see 7/1967), further revises and publishes Flood Hazard Evaluation Guidelines for Federal Executive Agencies.

6/1972

The Corps of Engineers publishes Flood-Proofing Regulations. State and local officials have subsequently requested more than 100,000 copies of this document.

6/1972

When Tropical Storm Agnes strikes the East coast, fewer than 1,200 communities participate in the NFIP, with only 95,000 policies and $1.5 billion of coverage in force. Consequently, less than 1 percent of insurable damages are covered. Agnes causes $400 million in structural damage, but only $5 million is paid in flood insurance claims.

7/1972

The NFIP's subsidized rates for flood insurance are lowered by 37.5 percent to encourage increased participation in the program.

10/1972

Congress approves the Water Pollution Control Act Amendments of 1972 (PL 92-500). Section 404 provides protection for wetlands and supplements the Corps of Engineers' existing permitting program for activities in navigable waters, pursuant to Section 10 of the Rivers and Harbors Act of 1899. That Act required permits for the discharge of dredged or fill materials into all "waters of the United States." Later court decisions interpret this provision to include most of the nation's wetlands.

10/1972

Congress passes the Coastal Zone Management Act (PL 92-583), one of several acts that emphasize protection and enhancement of environmental quality.

1972

The Water Resources Council publishes the second volume of Regulation of Flood Hazard Areas to Reduce Flood Losses. The volume explores in more detail techniques to regulate subdivision of lands in flood-hazard areas. Like the initial volume, the second volume contains draft regulations dealing with subdivision regulations and regulations of coastal flood hazard areas.

1972

The NFIP develops new insurance rate tables based on nationwide risk zones, which replace the former community risk zones.

4/1973

Comprehensive revisions to NFIP regulations become effective on April 1. The revisions include detailed criteria for floodplain management for communities and specific performance standards requiring the elevation or flood proofing of structures to the elevation of the 100-year flood.

5/1973

The Federal Insurance Administrator estimates that there are approximately 10,000 flood-prone communities in the United States, or about twice as many as had been estimated in 1968 (see 8/1968).

6/1973

In Water Policies for the Future, the National Water Commission raises concerns about the NFIP's high degree of subsidization as well as the practicality of withholding emergency relief from people who could have covered their losses by insurance but chose not to do so. The Commission further declares that the "role that flood insurance should play in a unified national program for reducing flood losses is not yet clear and there is a need for an independent study of present flood insurance legislation and activities." The report recommends increased funding for the Corps' Floodplain Management Services Program. Subsequently, the Office of Management and Budget approves more than $10 million for FY 1974 and comparable sums in the following years to fund the Corps' work on floodplain management.

6/1973

FIA initially relied on its small in-house staff to utilize base maps provided by communities desiring to participate in the NFIP, augmented by flood data generated by the Corps of Engineers, the USGS, and others to map flood hazards. As more communities are identified as being prone to floods, and as the number of participating communities increases, the scope of the mapping task exceeds FIA's internal capabilities. Therefore, FIA hires three engineering firms to identify communities for which flood data exist and to prepare Flood Hazard Boundary Maps (FHBMs). These firms are asked to identify communities for which flood data do not exist so that these communities can be referred to another federal agency for study and the generation of the flood data.

Before 1973, flood-prone areas shown on early FHBMs are shaded, delineated in a rectilinear or "blocked out" method (i.e., straight lines following easily identifiable land features such as streets and railroads). This practice makes the maps easy for lenders, insurance agents, and other laypersons to interpret but results in an artificial representation of the true flood boundaries, which are curvilinear and reflect the topography of the land. The use of blocked out flood boundaries is standard for all NFIP mapping until the passage of the Flood Disaster Protection Act (PL 93-234) in December 1973, which makes artificial rectilinear flood boundaries unacceptable, especially for large, undeveloped tracts of land.

7/1973

In Actions Needed to Provide Greater Insurance Protection to Flood-Prone Communities, the General Accounting Office (GAO) reports that FIA has no monitoring system to determine whether communities are effectively enforcing the floodplain management regulations they have adopted.

12/1973

The NFIP estimates that there are approximately 13,600 flood-prone communities in the United States (see 8/1968 and 5/1973).

12/1973

The Flood Disaster Protection Act of 1973 (PL 93-234) amends the National Flood Insurance Act of 1968. The new Act, effective in March 1974:

.. Increases the amounts of flood insurance available to property owners.

.. Requires property owners in participating communities to purchase flood insurance as a condition of receipt of federal or federally related financial assistance on or after March 2, 1974, for acquisition, construction, or improvement of structures in special flood hazard areas (SFHAs). In addition, purchase of flood insurance is required before property owners will be eligible to obtain federal disaster assistance for construction or reconstruction purposes.

12/1973

continued

.. Requires the NFIP to identify, by June 30, 1974, all communities that contain areas at risk for serious flood hazard and to notify these communities that they can apply for participation in the NFIP or they will be ineligible for certain types of federal assistance in their floodplains.

.. As a condition of future federal financial assistance, requires states and communities "to participate in the flood insurance program and to adopt adequate floodplain ordinances with effective enforcement provisions consistent with federal standards to reduce or avoid future flood losses." Participation must begin by July 1, 1975, or one year after notification that a community has flood-prone areas.

.. Requires FIA to consult with local officials to implement its flood-prone notification and identification procedures; to establish explicit procedures whereby communities can appeal their flood-prone identification; and to accelerate the insurance ratemaking studies.

.. Allows the Department of Housing and Urban Development to implement the NFIP on an emergency basis until December 31, 1975, while it completes determinations of flood-prone areas (see 12/1969).

.. Provides for grandfathering, for purposes of determining insurance rates, for structures built in flood-hazard areas before the areas are identified as such. These pre-FIRM structures are not required to comply with existing construction requirements.

.. Mandates that federally regulated lending institutions cannot make, increase, extend, or renew any loan on a property located in a SFHA in a participating community without requiring flood insurance.

.. Expands the definition of "flood" to include "flood-related erosion."

.. Repeals Section 1314 (denying disaster relief to persons who could have purchased flood insurance for a year or more and did not do so) because it is a disincentive to community participation.

In approving PL 93-234, Congress reaffirms the use of the 100-year flood as the standard for identifying SFHAs and establishing land-use requirements. SFHA have a 1-percent chance of being flooded in any given year (100-year floodplain).

12/1973

Over 2,850 communities are participating in the NFIP.

1973

The Nixon Administration issues New Approaches to Federal Disaster Preparedness and Assistance. The report concludes that federal assistance typically replaces rather than supplements nonfederal efforts. In addition, the report notes that federal assistance for disasters is often perceived to be sufficiently generous that "individuals, business, and communities had little incentives to take initiatives to reduce personal and local hazards" (House Document 93-100, 93rd Congress, First Session).

1973

The USGS expands aerial coverage of flood-prone area maps and pamphlets to include areas subject to future development. To guide this phase, the USGS publishes a National Program for Managing Flood Losses: Guidelines for Preparation, Transmittal, and Distribution of Flood-Prone Area Maps and Pamphlets to assist the Water Resources Division to prepare the maps.

1/1974

Effective January 1, 1974, rates for flood insurance are lowered to encourage wide acceptance of the new mandatory purchase requirement and to encourage increased sales of the insurance. This is the second such decrease (see 7/1972).

More than 2,850 communities (including 2,264 in the emergency program) are participating in the NFIP. About 312,000 policyholders have about $5.5 billion of coverage.

3/1974

The Water Resources Development Act (PL 93-251) authorizes federal projects containing major "nonstructural" features. Section 73 directs all federal agencies to consider nonstructural alternatives when reviewing any project involving flood protection and to pay at least 80 percent of the cost of nonstructural flood control measures.

5/1974

The Disaster Relief Act Amendments of 1974 (PL 93-288) authorize the president to make contributions to state and local governments to help repair, restore, reconstruct, or replace public facilities damaged or destroyed by a major disaster. Section 314 requires that applicants for such assistance must comply with regulations (to be developed) to assure that "such types and extent of insurance will be obtained and maintained as may be reasonably available, adequate, and necessary to protect against future loss to such property." The law prohibits the federal government from requiring "greater types and extent of insurance than are certified…as reasonable by the appropriate State insurance commissioner…."

States and communities receiving federal disaster assistance will be required to "agree that the natural hazards in the area in which the proceeds of the grants or loans are to be used shall be evaluated and appropriate action shall be taken to mitigate such hazards…."

The amendments represent the first congressional mandate for hazard mitigation as a precondition for federal disaster assistance.

6/1974

The Flood Disaster Protection Act of 1973 (see 12/1973) required that the Department of Housing and Urban Development identify all flood-prone communities and notify them of their special flood hazard areas by June 30. Of the 13,600 such communities so identified by December 1973, FIA had provided FIRMs or FHBMs to less than two-thirds. By June 1974, an additional 2,700 communities are identified as flood-prone. Once a community is informed that it is prone to floods, it has one year to qualify for the emergency program (see 12/1969) or six months to appeal its designation as a flood-prone community.

7/1974

FIA further reduces rates for flood insurance and introduces the direct bill system for renewal of flood insurance policies.

7/1974

The U.S. District Court for the Middle District of Pennsylvania grants a motion to dismiss a civil action filed by the Commonwealth of Pennsylvania, et al., against the United States, the Secretary of the Department of Housing and Urban Development, and the National Flood Insurers Association, alleging that the defendants negligently failed to make known the availability of flood insurance to Pennsylvanians who, as a result, suffered uninsured losses as a consequence of the June 1972 and 1973 floods in Pennsylvania. The aggregate damages suffered were alleged to be $1 billion. The U.S. Court of Appeals affirms the decision in June 1975.

8/1974

The Housing and Community Development Act of 1974 (PL 93-383) amends the National Flood Insurance Act of 1968 by adding Section 1364 (commonly known as the Jones' amendment), which requires federally regulated lenders to notify prospective borrowers of a property's location in a SFHA, and subsection (e) to Section 1307 (commonly known as the Brooks' amendment). In communities where adequate progress has been made on the construction of a federal flood-protection system that will afford protection against the 1-percent annual chance flood, the Brooks' amendment provides for the availability of flood insurance at risk premium rates that will not exceed those that would apply if such a flood-protection system had been completed.

10/1974

Due to the requirements of the Flood Disaster Protection Act of 1973 (see bullet 4 at 12/1973), the first Letter of Map Amendment (LOMA), which excludes a property from inadvertent inclusion in a SFHA, is issued. A LOMA amends an effective FIRM. The role of the three mapping contractors is expanded to process these map amendments.

The first community determined not to require a detailed study (i.e., minimal conversion) is converted to the regular program. Similarly, the first community determined not to be subject to inundation by the 100-year flood (i.e., non-flood-prone conversion) joins the regular program in 1974.

11/1974

FIA hires a contractor to develop and maintain a computerized management information system.

1974

Due to the accuracy required by the mandatory purchase requirement of the Flood Disaster Protection Act of 1973 (see 12/1973), 10,000 FHBMs must be revised to change the rectilinear boundaries of flood-prone areas to curvilinear boundaries.

1974

The first private company begins providing flood-zone determination services to lending institutions to assist them in complying with the mandatory purchase requirements contained in the 1973 Act.

2/1975

Given the large number of flood insurance studies in progress and FIA’s limited staff, two engineering firms, referred to as technical evaluation contractors (TECs), are contracted to review the study products that federal agencies create and to put the NFIP’s maps in standard format.

3/1975

In National Attempts to Reduce Losses from Floods by Planning for and Controlling Uses of Flood-Prone Lands, the GAO reports that federal agencies do not adequately evaluate flood hazards in their programs. Many of the agencies, the report notes, do not have or properly implement their flood-related procedures. In addition, the report observes, Executive Order 11296 (see 8/1966) has had limited effect in reducing flood losses due lack of implementing procedures and, among agencies that do have procedures, limited compliance.

3/1975

Proposed revisions to NFIP regulations are published in the Federal Register. The proposed revisions will allow minimum requirements for floodplain management to differ depending on the amount of technical data available to communities. Other proposed revisions will: allow the use, in establishing regulations, of data from other federal or state agencies or consulting services in communities where a FHBM has not yet been completed; require building permits for construction in SFHA when FHBM have been issued; require that all new construction must have the lowest floor above the 100-year flood level in communities with FHBMs and in which 100-year flood-surface elevations have been issued; and require new construction in coastal high hazard areas to keep the space below the lowest floor free from obstructions or use “break-away walls” when 100-year flood levels have been identified.

6/1975

Of the 21,411 communities that FIA has designated as flood-prone, 9,977 participate in the NFIP, but only 549 have FIRMs and are in the regular program.

Summer 1975

The National Flood Insurers Association hires its own staff and relocates its headquarters to suburban Washington, DC. The association assumes the functions that the Insurance Services Office previously handled and retains the servicing carrier concept.

7/1975

Flood insurance studies are produced under interagency agreement with other federal agencies through June, when FIA enters into contracts with engineering firms to produce data for flood insurance studies.

8/1975

Over 350 communities have appealed their designation as flood-prone. Based on the appeals, 136 were found not to be flood-prone. An additional 2,445 appeals have been received but not yet processed. Further appeals are possible because not all communities have been notified of their flood-prone status.

9/1975

The GAO reports in Tulsa, Oklahoma's Participation in the National Flood Insurance Program, that FIA "does not formally monitor the flood insurance program to insure that communities enforce approved flood plain management regulations" or those of FIA (see 7/1973). The report also notes that the GAO does "not question the validity of the 100-year flood level as the acceptable standard for flood plain management" (see 12/1973).

1975

Gilbert White founds the Natural Hazards Center at the University of Colorado, Boulder. The Center's primary goal is to strengthen communication among the researchers, individuals, organizations, and agencies that are concerned with individual and public actions to reduce damages from disasters.

1975

The Interagency Task Force on Floodplain Management is created (see Water Resources Council reorganizes, 1976).

3/1976

The Water Resources Council publishes Guidelines for Determining Flood Flow Frequency (Bulletin No. 17), an updated and revised Bulletin No. 15, A Uniform Technique for Determining Flood Flow Frequencies.

4/1976

The GAO, in Formidable Administrative Problems Challenge Achieving National Flood Insurance Objectives, concludes that FIA has made considerable progress in identifying flood-prone communities and in providing them with FHBMs (see 12/1969). In contrast, FIA has made limited progress in completing the necessary studies to move communities into the regular program. Delays have occurred, according to the GAO, because of: a) ineffective planning and scheduling of studies; b) delays in reviewing completed studies; and, c) ineffective coordination and use of federal resources. FIA faces a deadline of August 1, 1983, to complete its studies on all flood-prone communities (see 8/1968). To meet this deadline, FIA will have to increase its completion rate from about 91 studies per year to about 2,600 per year.

The report also notes that FIA still has “not established an effective system for monitoring community efforts to adopt and enforce required flood plain management regulations.” Consequently, in the words of the GAO, the federal government, “though heavily subsidizing the flood insurance program…had no assurance that the communities’ flood-prone lands were being developed wisely to prevent or minimize future flood losses” (see 7/1973 and 9/1975).

6/1976

The federal government shifts its fiscal year (FY), so that it will now end on September 30 instead of June 30, as had previously been the case. Thus, FY 1976 was 15 months long. Flood studies and surveys receive their greatest single-year appropriations, about $94 million. As a result, 2,300 flood insurance studies are initiated. This amount equaled the total number initiated in the previous five years.

7/1976

The Water Resources Council publishes A Unified National Program for Floodplain Management, which updates and revises House Document 465 (see 8/1966) in response to Section 1302 (c) of the National Flood Insurance Act of 1968. The report establishes the conceptual framework for floodplain management and recommends actions for improving such management and recommends “appropriate floodplain management programs and regulations or control measures as a prerequisite to federal expenditures for the modification of flooding on the impact of flooding.”

The report states that: “Delay in completion of flood insurance studies and the resultant delay of community participation in the Regular program may permit continued development and building at flood-prone locations and the subsequent grandfathering of these high risk developments under subsidized insurance rates.”

10/1976

HUD’s Federal Insurance Administration issues a Final Rule that introduces the terms “base flood” and “base flood elevation” and begins to phase out the use of the term “100-year flood.”

12/1976

Comprehensive revisions to the NFIP’s requirements for floodplain management become effective on December 31. These revisions remain the basis of the NFIP’s current requirements for floodplain management.

1976

The Water Resources Council reorganizes, abolishing all of its technical committees. The Federal Interagency Floodplain Management Task Force succeeds the Floodplain Management Technical Committee. The task force consists of representatives from the TVA; the Departments of Agriculture, Army, Commerce, Energy, Housing and Urban Development, Interior, and Transportation; the Environmental Protection Agency; and, eventually, the Federal Emergency Management Agency (FEMA), which was created in 1979 (see 6/1978 and 4/1979). State representatives, through the Association of State Floodplain Managers, attend the meetings as observers. The task force provides continuity of communication between member agencies on issues related to floodplain management.

1976

The NFIP adopts regulations that treat states as communities and accordingly makes flood insurance available for state-owned properties in SFHAs only if the state has adopted adequate regulations for the management of its floodplains. The state may also elect to self-insure its properties if suitable regulations are in place.

1976

Robert J. Hunter is appointed Federal Insurance Administrator.

5/1977

Executive Order 11988, Floodplain Management, revokes and supersedes Executive Order 11296 (see 8/1966), which had limited success in reducing flood losses. The new executive order directs federal agencies to assert a leadership role in reducing flood losses and losses to environmental values that floodplains serve. Federal agencies are to avoid actions in or affecting floodplains unless there are no practicable alternatives and to use the 100-year flood as the base flood standard for the NFIP. The executive order is intended, in part, to ensure that federal agencies do not undermine communities' implementation of regulations adopted to participate in the NFIP. The order directly references NFIP's criteria for floodplain management.

5/1977

Executive Order 11990, Protection of Wetlands, directs all Federal agencies to avoid, if possible, adverse impacts to wetlands and to preserve and enhance the natural and beneficial values of wetlands. Each agency is directed to avoid undertaking or assisting in wetland construction projects unless the head of the agency determines that there is no practicable alternative to such construction and that the proposed action includes measures to minimize harm.

8/1977

Concerned with delays in issuing flood insurance studies, FIA decides to circumvent the state review and approval process. The states in Region V object. FIA subsequently revises the study policy. The states' success in altering the policy change solidifies their cause and pushes them to form an association that eventually becomes the Association of State Floodplain Managers.

8/1977

The National Flood Insurers Association issues a termination notice to the arrangement with the Department of Housing and Urban Development in an attempt to bring to its attention, and that of Congress, the serious nature of the disagreements between the insurance pool and the government on issues of authority, financial control, and other operating matters.

10/1977

FIA hires two additional engineering firms to perform technical evaluation services because of the growing backlog of flood insurance studies in progress.

10/1977

Title VII of the Housing and Community Development Act of 1977 (PL 95-128) further amends the National Flood Insurance Act of 1968 through the "Eagleton Amendment." This amendment permits federally regulated or insured lenders to make conventional loans in flood-prone areas of nonparticipating communities and to require that notification be given as to whether federal disaster assistance would be available in the event of a flood disaster.

10/1977

continued

PL 95-128 also removes the prohibition against all forms of disaster assistance within the SFHA of “sanctioned” communities and imposes the ban only on federal disaster assistance related to a declared flood disaster; increases the additional limits of insurance coverage available at risk premium rates; provides additional criteria under which flood-damaged property can be eligible for purchase; and provides authority for low-interest loans for elevating structures located in floodways.

12/1977

Approximately 1.2 million flood insurance policies are in force, an increase of almost 900,000 over the number in December 1973. Community participation increases to approximately 15,000 in 1977 from approximately 3,000 in 1973.

12/1977

The Secretary of the Department of Housing and Urban Development and the National Flood Insurers Association sign an Assumption Agreement terminating the involvement of the National Flood Insurers Association in the NFIP, effective December 31, 1977.

1977

Following record floods in southwest Virginia, the TVA provides technical and financial assistance to four communities in floodplain evacuation and relocation. Local officials acquire several hundred properties, often as linear parks next to streams.

1977

Gloria Jimenez is appointed Federal Insurance Administrator.

1/1978

The federal government assumes the direct insurance writing and claims handling operation of the NFIP using an NFIP Servicing Agent to handle the sales and servicing responsibilities. Prospective policyholders continue to go through local agents and brokers to obtain their policies (see 6/1969 and 8/1977).

2/1978

The Water Resources Council publishes Guidelines for Implementing Executive Order 11988 – Floodplain Management. The report is designed to assist federal agencies in preparing regulations and procedures for implementing the order (see 5/1977). The document describes ways government agencies are to avoid supporting development in floodplains when a practicable alternative exists. As the Guidelines note, however, they “do not intend to prohibit floodplain development in all cases, but rather to create a consistent government policy against such development under most circumstances.”

5/1978

In Texas Landowners Rights Association v. Harris, 453 F.Supp. 1025 (D.D.C. 1978), the State of Missouri, 40 political subdivisions in 12 states, and 30 individual landowners within federally designated flood zones bring suit against federal officials administering the NFIP. The plaintiffs contend that requiring local governments to adopt regulations for building in floodplains under their police powers, on pain of losing federal financial assistance for acquisition or construction purposes within nonparticipating communities, violates the Constitution’s Tenth Amendment. This sanction includes denial of FHA and VA home mortgages in affected communities. The plaintiffs further argue that the severity of the sanctions is such that the “choice” represents no choice at all, but only coercion.

The court rejects the plaintiffs’ contention, holding that coercion is to be found only where the federal government gives the states no choice, but mandates compliance. In addition, the court rules that the NFIP's implementation is not a constitutionally prohibited taking of property without payment of just compensation.

The U.S. Circuit Court for the District of Columbia (598 F.2d 311, 1979) and the U.S. Supreme Court (cert. denied, 444 U.S. 927, 100 S.Ct. 267, 1979) subsequently upholds the lower court's judgment.

6/1978

President Carter forwards Reorganization Plan No. 3 of 1978 (House Document 95-356, 95th Cong., 2nd Sess.) to Congress. The plan calls for FEMA's establishment as an independent agency within the executive branch. The new agency will coordinate federal disaster response-and-recovery efforts and consolidate the programs of five related agencies (FIA, the Federal Disaster Assistance Administration, the Defense Civil Preparedness Agency, the Federal Preparedness Agency, and the National Fire Prevention and Control Administration). The new agency will begin to operate on April 1, 1979.

6/1978

The initial identification of flood-prone communities is essentially completed. More than 19,000 FHBMs have been produced.

6/1978

President Jimmy Carter's Water Policy Initiatives include proposals to fund the National Flood Insurance Act's Section 1362. The section allows FEMA to purchase certain insured properties that have either been substantially or repeatedly damaged and then to transfer the properties to a public agency to improve floodplain management.

10/1978

Only 2,818 of 16,116 participating communities are in the regular program; the rest remain in the emergency program (see 12/1969).

12/1978

The Corps of Engineers has completed 1,800 Floodplain Information Reports covering 3,500 communities.

3/1979

The GAO reports to the secretary of the Department of Housing and Urban Development that use of the 100-year flood "as the single national standard of regional flooding conditions has caused considerable controversy over the years." Noting that there were 127 floods between 1968 and 1978 that equaled or exceeded the 100-year flood level in 62 counties, the GAO recommends an evaluation of the 100-year flood as a national standard. This recommendation contradicts GAO's earlier conclusion (see 9/1975) that the 100-year flood standard is suitable.

The same report notes continuing deficiencies in FIA's monitoring of communities' compliance with the NFIP's requirements (see 7/1973, 9/1975, and 4/1976). The GAO observed that FIA makes relatively few visits to communities and "major differences in the approach, scope, and duration of the visits conducted by personnel from two different [FIA] regional offices."

4/1979

On April 1, FIA and the NFIP are transferred from the Department of Housing and Urban Development to the newly created FEMA.

8/1979

FEMA publishes a proposed rule in the Federal Register that will allow flood-proofed residential basements in all communities. This rule is in response to demand for basements in some areas of the nation. The proposed rule is withdrawn in March 1981 after it is determined that flood-proofed basements can pose an unacceptable threat to public safety under some flooding conditions.

8/1979

John Macy is appointed FEMA Director.

9/1979

An initiative to decentralize the production of maps to individual contractors is implemented. It is subsequently determined that this is not a cost-effective approach. The previous system of having the technical evaluation contractors produce the maps through printing by the Government Printing Office is re-instituted.

The acquisition program for flood-damaged properties provided for in Section 1362 of the National Flood Insurance Act of 1968 is funded for the first time (see 6/1978). Just over 100 properties are acquired in FY 1980. Over the next 14 years, approximately 1,400 properties are purchased at a cost of nearly $52 million. In addition to funding for Section 1362, Congress also provides funds for the State Assistance Program to develop floodplain management capabilities.

9/1979

Hurricane Frederic strikes Gulf Shores, Alabama, and nearby coastal communities causing severe damage to structures. This results in considerable controversy about the adequacy of the NFIP's V-zone construction standards; criteria used to designate V-zones and V-zone flood insurance rates; and whether wave heights should be added to coastal base flood elevations.

9/1979 continued

Note: V-zones or coastal high hazard areas are the most hazardous coastal flood zones because they are subject to high velocity wave action. V-zone designation is applied only to those areas along the coast where water depth and other conditions support at least a three-foot wave height.

9/1979

A revised version of A Unified National Floodplain Management Program is published and concludes that the NFIP "provides persuasive strength and beneficial emphasis to floodplain management."

9/1979

By the end of Fiscal Year 1979, nearly 16,600 communities are participating in the NFIP, with 3,381 in the program's "regular phase." There are more than 1.6 million policies in force, covering about $60 billion in property. Throughout the program's life, total claims have exceeded 146,000, and total payments to victims have exceeded $572 million.

12/1979

Approximately 1.85 million flood insurance policies are in effect, representing $74.5 billion in coverage. More claims (86,360) are filed in 1979 than in any subsequent year through 1999.

3/1980

A proposed rule is published in the Federal Register that would prohibit the use of solid breakaway walls to enclose areas below the base flood elevation in V-zones. In 1981, after a change in presidential administrations, the proposed rule is withdrawn after the Office of Management and Budget raises concerns that the rule revision is an unnecessary intrusion into the management of local affairs.

4/1980

Damages from Hurricane Frederic result in a decision to incorporate wave heights into base flood elevations in coastal areas. The impact of wave heights on coastal flood levels is first added to FIRM for seven communities in Alabama.

5/1980

FEMA adopts a policy that requires state and local governments to agree to pay 25 percent of the eligible costs of public assistance programs (other than individual and family grants). Prior to this time, the required nonfederal contribution was subject to negotiation between FEMA and the affected state and local governments.

6/1980

The Office of Management and Budget's memorandum, "Nonstructural Flood Protection Measures and Flood Disaster Recovery," directs that "all Federal programs that provide construction funds and long-term recovery assistance must use common flood disaster planning and post-flood recovery procedures." In response, 12 federal agencies approve an interagency agreement to provide technical assistance to states and communities for nonstructural measures to reduce flood damage in flood-recovery efforts. The agencies form an Interagency Flood Hazard Mitigation Task Force with responsibility for implementing agreement.

In subsequent disasters interagency teams are sent to investigate opportunities to employ nonstructural mitigation measures and to issue recommendations before recovery and reconstruction advance to the point where such measures could not be considered.

6/1980

FIA's management explores ways in which the private insurance industry's state windpools can be used to assure prompt claims service in a major post-flood hurricane disaster. The Single Adjuster Program is established. In this voluntary program, individual windpools, or coastal plans, and the NFIP agree in advance on the use of single adjusters to adjust both the wind and water damage from hurricanes and to recommend the claim payments by each insurer for risks that both a coastal plan and the NFIP insure.

9/1980

FEMA's regulations implementing Executive Order 11988, Floodplain Management, and Executive Order 11990, Protection of Wetlands, are effective on September 9. Although the primary focus of these regulations is on disaster assistance, provisions are included to limit flood insurance coverage for certain structures in floodways and for new structures in V-zones where wave heights are not included in base flood elevations. On November 28, FEMA publishes a notice of intent not to enforce these provisions. Instead, an interim rating system is developed that includes a calculation of wave height on a case-by-case basis.

10/1980

The Engineering Scientific Data Package (ESDP) system is established to archive and retrieve selected documentation necessary to recreate the elevation information presented in a flood insurance study.

12/1980

FIA promulgates a methodology for assessing the flood hazards unique to alluvial fans in the arid West.

1980

Regulation of Flood Hazard Areas to Reduce Flood Losses is revised to emphasize the lessons drawn from experiences with floodplain management in the 1970s. The Regulation focuses on state and local programs, including innovations that can exemplify effective reductions in flood losses in the future.

1980

FIA pilots a centralized map information facility, which uses state-of-the-art technology to develop a centralized database of the flood zone for individual structures that could be accessed by calling a toll free number. The pilot was discontinued in 1981 because available technology was inadequate, the system was not cost-effective, and the private sector was beginning to provide this service.

1/1981

In Requests for Federal Disaster Assistance Need Better Evaluation, the GAO recommends that FEMA “reevaluate and improve its assessment criteria” for disaster and emergency declarations. The GAO had found a “lack of consistency in the quality and methods” of assessing requests from governors for declarations.

1/1981

Rates for flood insurance are increased by 19 percent for pre-FIRM structures (i.e., structures for which construction or substantial improvement started on or before December 31, 1974, or before the effective date of a community’s initial FIRM, whichever is later). The rate increase is the first in the NFIP’s history.

The initial legislation creating the NFIP allowed these rates to be substantially lower than actuarial rates in an effort to promote communities participation in the program. The rate increase in 1981, the first since the NFIP’s creation, begins an effort to increase rates gradually to reduce, but not eliminate, the amount of subsidy and to make the NFIP self-supporting for the average historical loss year by 1988.

5/1981

Louis O. Giuffrida is appointed FEMA Director.

6/1981

An interim policy for accreditation of levees as providing 100-year protection on NFIP maps is promulgated. This policy is finalized in 1986 with its publication in the Code of Federal Regulation, Title 44, Chapter 1, Section 65.10 (see 10/1986).

8/1981

Section 341 of the Omnibus Budget Reconciliation Act of 1981 (PL 97-35) terminates, effective October 1, 1983, flood insurance coverage for new construction and substantial improvements of structures on undeveloped coastal barriers designated by the Secretary of the Department of Interior. FEMA participates in the Coastal Barriers Task Force the Secretary establishes to designate the undeveloped coastal barriers. The Coastal Barrier Resources Act of

1982 (PL 97-348) later overtakes and supersedes this process (see 10/1982).

8/1981

Section 1345 of the 1968 Act, governing services by the insurance industry, is amended to include subsection (c), which holds harmless insurance agents or brokers for the errors and omissions of FEMA.

8/1981

In Till v. Unifirst Federal Savings and Loan Association (653 F.2d 152), the U.S. Court of Appeals for the Fifth Circuit concludes that the National Flood Insurance Act does not provide an express or implied federal statutory cause of action against a federally regulated lending institution for failing to require flood insurance or to notify a prospective borrower that a dwelling is in a floodplain. In subsequent years, U.S. Courts of Appeals for the Fourth Circuit (Arvai v. First Federal Savings and Loan Association, 698 F.2d 683, 1983), the Seventh Circuit (Mid-America National Bank of Chicago v. First Savings and Loan Association of South Holland, 737 F.2d 638, 1984), and the Eighth Circuit (Hofbauer v. Northwestern National Bank of Rochester, 700 F.2d 1197, 1983) reach similar conclusions.

9/1981

The NFIP establishes a methodology to assess the contribution of wave run-up to flood elevations for communities along the open coast. This methodology is applied in several communities in Maine that had initiated flood insurance studies during FY 1981.

9/1981

FIA establishes a goal for the NFIP to achieve self-supporting status for an average historical loss year by 1988. Achieving this goal would mean the elimination of subsidies for pre-FIRM properties.

9/1981

FIA opens discussions with representatives of the insurance industry concerning re-involvement in the NFIP that ultimately develops into the Write Your Own (WYO) Program (see 10/1983).

10/1981

FEMA begins to use information on floods developed for purposes other than the NFIP (e.g., flood-flow estimates developed to size road crossings and bridges by state highway departments) as a cost-savings measure.

A new rating system for post-FIRM V-zone buildings is implemented to reflect the additional risk of surge and wave height and to offer an individual risk-rating option. Post-FIRM properties are those for which construction or substantial improvement started on or after the effective date of a community's initial FIRM or after December 31, 1974, whichever is later.

1981

The Water Resources Council updates Bulletin No. 17, Guidelines for Determining Flood Flow Frequency (Bulletin 17B of the Hydrology Committee, U.S. Water Resources Council). This document, first published in 1967 (Bulletin No. 15), is the guide most government agencies use when conducting flood-frequency studies.

1981

The NFIP's premium rates are increased by 45 percent for pre-FIRM structures, as part of FEMA's effort to reduce subsidies and to make the NFIP self-supporting for an average historical loss year. Over the next seven years rates will increase by 120 percent.

1981

Jeffrey S. Bragg is appointed Federal Insurance Administrator.

4/1982

Approximately 62 percent of premiums paid for flood insurance are subsidized.

8/1982

As part of President Ronald Reagan's Task Force on Regulatory Relief, created in January 1981, the Office of Management and Budget directs FEMA to investigate whether federal agencies are complying with the requirements of Executive Order 11988, issued in May 1977. In addition, FEMA is to: a) determine what impact, if any, the executive order is having on the level of federal support in designated flood-hazard areas and b) review the base, or "100-year" flood standard used in implementing the executive order.

8/1982

The GAO, in National Flood Insurance: Marginal Impact on Flood Plain Development, Administrative Improvements Needed, concludes that FEMA needs a better monitoring program to assure that local communities are enforcing floodplain regulations. According to the report, many premiums for flood insurance are based on erroneously designated (misrated) flood zones. In addition, the report concludes that this insurance creates a "marginal added incentive for development in coastal and barrier island communities."

9/1982

Funding for the Water Resources Council ceases, although the Council is never officially dissolved.

10/1982

The Coastal Barrier Resources Act (PL 97-348) creates the Coastal Barrier Resources System (CBRS). The Act prohibits new federal expenditures (including the issuance of new federal flood insurance and most disaster assistance for new construction and substantial improvements) in designated units of the CBRS on the Atlantic and Gulf Coasts on and after October 1, 1983. Existing flood insurance policies can remain in force.

1982

The third volume of Regulation of Flood Hazard Areas to Reduce Flood Losses, started at the time of the Water Resource Center's demise, is subsequently completed and published by the TVA. The three volumes advance the understanding and application of land-use regulations in flood- hazard areas as a principal tool in reducing vulnerability to flood risk.

1/1983

Due to what the GAO labels as data and methodological weaknesses in the determination of rate structures, the GAO finds that the NFIP has not collected sufficient premiums to cover the cost of providing insurance to almost two million policyholders. As a result, National Flood Insurance Program: Major Changes Needed if it is to Operate without a Federal Subsidy points out that FIA had to borrow $854 million from the Department of the Treasury between 1970 and 1980.

2/1983

A system to maintain an inventory of levees, by community name, accredited as providing 100-year protection on NFIP maps begins.

2/1983

In The Effect of Premium Increases on Achieving the National Flood Insurance Program's Objectives, the GAO finds that FEMA's decision in January 1981 to raise rates for flood insurance policies has led to a decline in the total number of policies, from 2.01 million policies in the month before the rate increase to 1.86 million in November 1982. The GAO identifies several additional factors, such as a decline in the housing market and a smaller number of recent floods that might explain the decrease in the number of policyholders.

4/1983

Responsibility for flood insurance studies and for the issuance of single-lot, single-structure, Letters of Map Amendment and Letters of Map Revision is decentralized to FEMA's regional offices.

4/1983

In Approaches for Converting National Flood Insurance Program Communities from the Emergency Phase to the Regular Phase, the GAO concludes that FEMA will not meet the August 1983 deadline contained in the National Flood Insurance Act of 1968 for providing FIRMs for all flood-prone communities. The GAO explains that the missed deadline is due both to the complexity of the task and that FEMA has not used less costly and time-consuming techniques to produce the maps. The GAO also notes FEMA's estimate that approximately $153 million will be required to complete the mapping effort.

The GAO further observes that the imminent expiration of the emergency program in May 1983 (see 12/1969) will mean that over 290,000 policyholders will lose coverage unless Congress acts to extend the program.

9/1983

FEMA completes The 100-year Base Flood Standard and the Floodplain Management Executive Order, which the Office of Management and Budget had requested in August 1982 (see 8/1982). The President's Task Force on Regulatory Relief had selected Executive Order 11988 on Floodplain Management and the 100-year standard for review. The report concludes that both the 100-year standard and the executive order should be retained. For example, the report concludes that the 100-year base flood "is strongly supported and being applied successfully by all levels of government…and no alternatives have been identified that are superior to it…." In addition, however, the report concludes that some federal agencies have not adopted procedures to implement the executive order. Other agencies have adopted procedures, but they are not consistent with the executive order.

10/1983

In recognition of the 1968 Act's purpose that FIA arrange for appropriate participation in the NFIP by private-sector property insurers, flood insurance becomes available from insurance companies that had entered into an arrangement with the Federal Insurance Administrator to sell and service flood insurance under the Write Your Own (WYO) Program. At the time, there were 1,897,176 policies and slightly over $111 billion of coverage in force. During the first year, 48 companies agreed to become WYO participants in FY 1984. The first WYO policies are sold in November 1983.

10/1983

The map revision and technical evaluation contractor services are consolidated and the number of technical evaluation contractors is reduced from seven to three as the requirements for the flood insurance study program are changed.

10/1983

Effective October 1, the NFIP revises the rate schedules for flood insurance premiums and makes significant amendments to flood policies. To simplify insurance ratings, the NFIP groups Zones A1 to A30 under a single set of schedules and makes a similar reduction for Zones V1 to V30. Optional, higher deductibles become available so policyholders concerned with catastrophic protection can reduce their flood insurance premiums. In addition, flood insurance policies no longer cover:

.. Finished walls, floors, ceilings, and other similar improvements to basement areas;

.. Enclosures and building components located below the lowest elevated floor of an elevated building except for the required utility connections and the footing, foundation, anchorage system, etc. required to support the elevated building; and

.. Contents building machinery and equipment located in a basement area or below the lowest elevated floor of an elevated building, except stairways not separated from the building. For buildings where construction started before this date, coverage continues for sump pumps, water tanks, oil tanks, furnaces, hot water heaters, washers, dryers, freezers, air conditioners, heat pumps, and electrical boxes.

10/1983

FIA limits flood insurance coverage for basements to reduce future flood-claim payments. This action is based on FIA's findings that, between 1978 and 1982, the claim-loss frequency of buildings with basements was almost four times higher than the claim-loss frequency for buildings without basements. As a result of the change, the NFIP will no longer provide unlimited coverage of the contents of basements or finished walls, floors, ceilings. Coverage will continue for such items as oil tanks, furnaces, hot water heaters, heat pumps, and air conditioners.

10/1983

Continued

The controversial nature of the change in coverage leads to several lawsuits, which are decided in favor of FIA, as well as a report by the GAO (see Federal Emergency Agency's Basement Coverage Limitations, completed in 1/1986).

11/1983

The Housing and Urban-Rural Recovery Act of 1983 (PL 98-181) extends until September 30, 1985, the deadline for the establishment of flood-risk zones in floodplain areas and requires FEMA to submit to Congress a plan for bringing all communities containing flood-risk zones into full program status by September 30, 1987. The Act also prohibits any increase in premiums charged for flood insurance before September 30, 1984, and directs FEMA to submit a report to Congress explaining the rate structure and any rate increase anticipated before October 1, 1985.

FEMA subsequently notifies Congress that all remaining flood studies can be completed by 1991.

1983

The TVA publishes Floodplain Management: The TVA Experience to provide information about the authority's approach to working with state and local officials in floodplain management.

1983

The TVA joins with the Natural Hazards Research and Applications Information Center at the University of Colorado to evaluate the effectiveness of efforts to prevent flood damage. The Center forms an advisory group of national experts in floodplain management, develops the initial evaluation procedures, and conducts a pilot test in several area communities. The results are published in Determining the Effectiveness of Efforts to Reduce Flood Losses: The TVA Experience.

1/1984

In response to FEMA's review of the 100-year base flood standard (see 9/1983) the Office of Management and Budget (OMB) agrees that "the 100-year base flood standard appears to be working well and, given its widespread use, it does not appear to be in the public interest to adopt another methodology."

5/1984

The first countywide FIRM, for Marion County, Indiana, becomes effective. The FIRM shows the flood risks for all incorporated communities within the county as well as its unincorporated portions.

6/1984

A demographic survey of communities participating in the NFIP's Emergency Program identifies those communities where expected development in the floodplain would justify incurring the costs of a detailed study.

9/1984

A Risk Studies Completion and Full Program Status Plan is submitted to Congress by FEMA (see 11/1983). The plan identifies how cost-containment measures will be implemented to achieve the most economical conversion of about 7,000 communities to the Regular Program on or before September 30, 1991. A benefit-cost strategy is promulgated to standardize decision-making as to which communities will be converted by other means.

9/1984 continued

Largely because of the results of the demographic survey completed in June and the application of benefit-cost considerations, emphasis is given to converting low-growth communities to the Regular Program through the minimal conversion process. As a result, 1,871 conversions to the Regular Program occur in FY 1984. This is the largest number of conversions in any year of the NFIP's history.

1/1985

The Map Initiatives Project is completed after more than two years of review and discussion by a task force comprised of representatives from the major user groups. Consequently, a new format is specified for NFIP maps to make them more "user-friendly." Changes include a reduction in the number of risk zones from 68 to 9; the elimination of flood-hazard identification dates; and the consolidation of essential information on flood insurance and floodplain management on one map, thus eliminating the need for separate FIRM and FHBM.

9/1985

FIA publishes Appeals, Revisions and Amendments to Flood Insurance Maps – A Guide for Community Officials, a document written in lay language to explain the mechanisms for revising or amending NFIP maps. More than 12,000 copies of this manual are distributed before it is revised in January 1990.

10/1985

The first of more than 500 Limited Detail Studies (LDS) is initiated as a cost-containment measure to provide flood-risk zones and base flood-elevation information to communities that would experience low-to-moderate development pressure in their SFHA during the 15-year period beginning in 1985.

10/1985

The Community Assistance Program (CAP) is established to provide assistance on floodplain management to communities by drawing on resources in addition to FEMA's regional offices. The State Support Services Element, which replaces the State Assistance Program, uses states to provide this assistance. Similarly, the Federal Support Services Element makes use of federal agencies such as the TVA, USGS, the Corps of Engineers, and the Soil Conservation Service.

10/1985

The NFIP's Community Compliance Program (CCP) is established to provide a credible means to ensure that communities adequately enforce regulations on floodplain management adopted as a condition of participation in the NFIP. The program provides procedures for the probation and suspension of communities and the denial of flood insurance for individual structures under Section 1316 of the National Flood Insurance Act and builds on the mutually supportive relationship between flood insurance ratings and floodplain management.

10/1985

The Corps of Engineers' National Flood Proofing Committee is formed to advance the application of flood-proofing techniques.

11/1985

Julius W. Becton, Jr. is appointed FEMA Director.

1985

The TVA publishes A Guide to Evaluate a Community's Floodplain Management Program to document how others could use the TVA's evaluation procedures to judge community floodplain management programs.

1985

The first Annual Report of the Association of State Floodplain Managers summarizes activities of state initiatives and resources independent of the NFIP. The annual report represents slightly more than half the states and is not compiled through a formal survey.

1/1986

The NFIP's regulations are revised on January 1 to provide a probation procedure for participating communities that fail to adequately enforce floodplain-management measures adopted to meet NFIP criteria. As part of probation procedures, a $25 surcharge applies for any flood insurance policy newly issued or renewed on and after October 1, 1986, for any property that is located within a community that is on probation. This is intended to be an interim process, short of community suspension, to increase public awareness of the situation and to encourage community officials to take the actions necessary to comply with the NFIP's requirements for floodplain management. Revisions are also made to V-zone construction requirements and other criteria for floodplain management.

1/1986

FIA publishes A Standardized System for Flood Insurance Restudy Identification and Prioritization to systemize decision making about communities that are candidates for restudy and to assure that only cost-effective restudies are initiated.

1/1986

FIA implements a fee-charge system for certain categories of conditional letters of map correction to recover the cost of providing engineering services to review and comment on proposed developments in participating communities' floodplains.

3/1986

A revised Unified National Program for Floodplain Management notes that the previous report has again become dated by the relative success and changes in federal programs and by the strengthening of floodplain management at the state and local levels. The report, building on earlier reports and subsequent legislation, directives, and activities, establishes two broad goals for floodplain management: to reduce loss of life and property from flooding and to reduce loss of natural and beneficial resources from unwise land use.

The report urges that development in high hazard areas be avoided, except in instances of public interest or in the absence of a suitable alternative.

4/1986

FEMA proposes to change the process of declaring disasters; the criteria for eligibility for federal assistance; and the nonfederal responsibility for major disasters. The proposed regulations would also decrease the federal share of disaster costs to 50 percent from 75 percent. Furthermore, states would be required to meet certain economic criteria before they would be eligible to receive federal assistance and to increase their cost-sharing responsibilities, along with that of local governments, for disaster assistance.

Due to strong opposition in Congress, FEMA subsequently withdraws the proposed rules.

9/1986

Harold T. Duryee is appointed Federal Insurance Administrator. He remains in this position until August 1990.

9/1986

FIA produces the first digital FIRM, for Tulsa, Oklahoma. A five-year, $20 million program to digitize 25,000 FIRM panels for about 340 counties that account for about 75 percent of all property-at-risk begins.

10/1986

The NFIP's regulations on floodplain management are revised. Major changes affect placement of manufactured homes, mechanical and utility equipment, openings for enclosures, use of available flood data, and functionally dependent uses. The revisions also formally terminate the State Assistance Program and establish procedures for denial of insurance under Section 1316, obtaining basement exceptions, revision of flood maps, and the recognition of levees. The revisions result in the first required update of all NFIP community ordinances since the 1976 rule revisions.

10/1986

On October 1, the NFIP makes the following amendments to the standard flood insurance policy:

.. Buildings in the course of construction that are not walled or roofed are eligible for coverage. The standard deductible for these buildings is double the post-construction amount and buildings in selected zones with the lowest floor below the base flood elevation are not eligible.

.. When an insured building has been inundated by rising lake waters continuously for 90 or more days, and it appears reasonably certain that a continuation of this flooding will result in damage reimbursable under the flood policy, the insurer can pay the insured without waiting for further damage to occur. To receive payment, the insured must sign a release agreeing not to make further claims under the policy, not to renew the policy, and not to apply for NFIP insurance for a new property at the same location.

.. For mobile homes in mobile home parks or subdivisions, the date of construction to determine pre- or post-FIRM status is the date a mobile home is placed on its foundation.

1/1987

Effective January 1, the standard policy covers reasonable expenses incurred for the temporary removal and storage of insured property because of the imminent danger of flooding up to the amount of the minimum building deductible. The policy no longer provides coverage for the cost of repairs to protect insured property damaged by flood from further damage.

1/1987

President Ronald Reagan's proposed budget for the next fiscal year recommends that all subsidies for flood insurance be eliminated and that rates be increased in order to recover "the clearly allocable costs of flood insurance from beneficiaries." The Reagan Administration also states that flood insurance can be provided at affordable rates for homeowners by the private sector.

Spring 1987

A task force is created to investigate the feasibility of using the insurance industry's services and facilities and, if feasible, to develop procedures for implementing a Community Rating System (CRS). CRS would recognize a community's efforts to undertake floodplain management activities beyond those required for participation in the NFIP; increase the public's awareness of flood insurance; and assist property owners, insurance agents, and lenders seeking individual property flood-risk information.

7/1987

FIA inaugurates a Limited Map Maintenance Program (LMMP) as a cost-containment measure to process, in an expedient manner, revisions to NFIP maps that are limited in scope. Authority to task federal agencies to perform LMMP projects under interagency agreements is decentralized to FEMA's regional offices.

7/1987

The Supplemental Appropriations Act of 1987 (PL 100-71) suspends through September 30, 1988, those portions of the rule revision (of October 1, 1986) applicable to existing manufactured home parks and subdivisions. The Act also requires FEMA to prepare a report on the impact of the regulations. The report is submitted to Congress in September 1988.

10/1987

For the first time, the NFIP becomes self-supporting for the historical average loss year. For the NFIP, the intent is to generate premiums at least sufficient to cover expenses and losses relative to what is called the historical average loss year, which differs from the traditional insurance definition of solvency. During FY 1986, no taxpayer funds are required to meet the NFIP's flood insurance expenses. In addition, at the beginning of the fiscal year, the NFIP is required for the first time to pay all program and administrative expenses with funds derived from insurance premiums. Prior to this time, program costs for administrative expenses, surveys, and studies, are financed through congressional appropriations.

12/1987

Approximately 2.1 million flood insurance policies are in force, representing $165 billion in coverage. The program's net operating deficit is about $652 million.

1987

Minnesota establishes a Flood Hazard Mitigation Grant Assistance Program, which will provide a 50-percent state/50-percent local, cost-share grant program for activities to reduce damages from floods.

1987

The Unified National Program for Floodplain Management recommends the evaluation of "floodplain management activities with periodic reporting to the public and to Congress on progress toward implementation of a unified national program for floodplain management." To implement this recommendation, the Federal Interagency Floodplain Management Task Force initiates an assessment of the nation's program for floodplain management. The national assessment provides a comparative basis for justifying program budgets and evaluating, over time, the effectiveness of various tools, policies, and planning efforts for floodplain management.

4/1988

FIA inaugurates a fee-charge system to require certain requestors of NFIP maps to reimburse the National Flood Insurance Fund for the costs of map-ordering services. Entities required to use the NFIP maps as part of the program's implementation are exempt from these fees (i.e., local, state, and federal agencies, insurance agents, and lenders).

A pilot marketing analysis is conducted to determine if map users are interested in purchasing microfilm copies of NFIP maps as opposed to purchasing these maps in hard-copy paper format. The results of this analysis identify a small market and limited interest in microfilm.

4/1988

In Statistics on the National Flood Insurance Program, the GAO summarizes data on the program's operations through the end of FY 1987.

5/1988

To reduce the NFIP's subsidy levels without using a rate increase, NFIP regulations are amended to increase the standard building and contents deductible for pre-FIRM properties to $1,000 from $750. Policyholders who wish to have lower deductibles are given the option to "buy back" a $500 deductible separately for building and contents coverage.

5/1988

Due to record high-water levels in the Great Lakes, the Housing and Community Development Act of 1987 (PL 100-242) amends the National Flood Insurance Act of 1968 (through what is called the “Upton-Jones Amendment”) to provide insurance benefits to structures in imminent danger of collapse due to coastal erosion or undermining caused by waves or water levels exceeding cyclical levels. Following a local government’s condemnation of a structure, the payment from flood insurance would be 40 percent of the structure’s value prior to collapse and, following demolition, 60 percent of the structure’s value. The approach represents the first federal use of erosion setbacks as a tool for preventive management as part of an insurance program.

The Act also authorizes the president to contribute to states and local communities up to 50 percent of the cost of measures to mitigate hazards that substantially reduce the risk of future damage or loss in any area affected by a major disaster. Contributions cannot exceed 10 percent of the Public Assistance grants made with respect to the disaster or $1 million, whichever is greater.

6/1988

The Claims Coordinating Office (CCO) is developed to facilitate the entrance of multiple WYO companies into the Single Adjuster Program. When major storm events occur, a CCO will be established within Integrated Flood Insurance Claim Offices (IFICO) to provide a central clearinghouse for loss adjuster assignments and data sharing, for the use of WYO companies, coastal plans, and certain other property insurers willing to participate in coordinating a claims-oriented response to the catastrophe. Subsequent experience indicates that IFICO handle losses efficiently while coordinating activities with private sector windpool associations, WYO companies, and FEMA’s Disaster Field Office and Disaster Assistance Centers.

10/1988

FIA restructures commissions to encourage the sale of flood insurance. The commission provisions for the WYO Program are also restructured under a program to be re-evaluated in 1990. The provisions allow for commissions equal to 14 percent of premiums with the opportunity to earn an additional commission of one-tenth of 1 percent for each 1-percent increase in a company’s total policies in force up to a total commission of 17 percent of premium.

10/1988

The coverage limitation for enclosures (and contents) below an elevated structure is revised effective October 1 to apply only to elevated post-FIRM buildings (i.e., buildings for which the start of construction or substantial improvement occurred on or after the effective date of the FIRM or after December 31, 1974, whichever is later).

11/1988

The Robert T. Stafford Disaster Relief and Emergency Assistance Act (PL 100-707) emphasizes hazard mitigation including funds to acquire or “buyout” destroyed or damaged properties and to not rebuild in SFHAs; to rebuild in nonhazardous areas; and to reduce exposure to flood risk in reconstruction.

The Act authorizes the allocation of up to 10 percent of FEMA’s Public Assistance grants for hazard-mitigation projects, that are cost effective and that substantially reduce the risk of future damage, hardship, loss, or suffering. Benefit-cost analysis is the recommended approach for determining cost-effectiveness. Buyouts are also approved. When buyouts are authorized, they are available to all affected residents of a flood-damaged area.

Section 404 establishes a Hazard Mitigation Grant Program. Grants are available to state and local governments and certain nonprofit organizations to implement long-term hazard mitigation measures following a presidential declaration of disaster. These measures can include projects to reduce the risk of future damage, hardship, or loss or suffering from damages. Buyouts are one type of eligible mitigation measure. Potential recipients of the grants, which can cover up to 50 percent of the costs of these activities, must maintain insurance as a condition of receipt.

1988

South Carolina acts to restrict new development along erosion-prone beachfronts.

1988

The Casualty Actuarial Society releases a Statement of Principles Regarding Property and Casualty Insurance Ratemaking. The statement identifies and describes principles applicable to the determination and review of rates for property and casualty insurance. The principles provide the foundation for the development of actuarial procedures and standards that seek to protect the insurance system's financial soundness and to promote equity and availability for insurance consumers.

1988

The Department of the Interior estimates that not developing 39,000 acres of developable coastal barrier land proposed to be added to the Coastal Barrier Resources System (see 10/1982) will save the federal government approximately $3 billion, which includes subsidies for flood insurance.

1/1989

Two new products, the Condominium Master Policy (CMP) and the Preferred Risk Policy (PRP), become available for the first time. The CMP provides insurance coverage at a significantly reduced cost under a single policy for residential condominiums with five or more units and three or more stories located in Regular Program communities. The PRP is available to the owners of one- to four-family residential buildings located in Regular Program communities provided the buildings are located outside of SFHA and have favorable flood-loss histories. The PRP has a new, simplified application form tailored to several fixed, limited-coverage combinations.

2/1989

FIA completes its assessment of future resource requirements, including both staffing and funding levels, needed to maintain the currency and accuracy of published NFIP maps. These resource requirements, identified in A Cost Effective Plan for Flood Studies Maintenance, describe how FIA will move from an "initial studies" phase to a "maintenance" phase for flood studies and surveys.

5/1989

Through the use of an interim rule, FEMA decides that federal disaster assistance to restore insurable structures in SFHAs will be reduced by the maximum amount of insurance proceeds that would have been received had a building and its contents been fully covered by a flood insurance policy. The interim rule is revoked in December 1991.

5/1989

Under the auspices of the Domestic Policy Council's Working Group on the Environment, Energy, and Natural Resources, the White House establishes an Inter-Agency Task Force on Wetlands. One of the group's primary objectives is to recommend revisions to existing presidential executive orders on wetlands protection and floodplain management (see 5/1977).

6/1989

The Enhanced Actuarial Information System is completed and used for the first time in conducting the annual review of NFIP rates.

9/1989

Hurricane Hugo strikes, wreaking havoc in the Carolinas, Puerto Rico, and the Virgin Islands. Buildings that had been built to meet the NFIP's requirements for floodplain management performed well, demonstrating the effectiveness of the requirements in reducing flood damages.

9/1989

The first major test of the Claims Coordinating Office (CCO) system occurs when a CCO is established to coordinate the assignment of a single adjuster to handle the wind and flood claims in North and South Carolina. The system works well and proves that cooperation between windpool and WYO companies through the CCO benefits insured individuals by simplifying the claims process with the use of a single adjuster.

10/1989

FIA implements a fee-charge system for certain categories of requestors of the archival backup for flood insurance studies and restudies. The fee-charge system is needed to limit the increasing costs associated with the servicing of these requests.

10/1989

Effective October 1, new rules revise the definition of substantial improvement and, for the first time, define substantial damage. "Substantial improvement" represents any reconstruction, rehabilitation, addition, or other improvement of a building, the cost of which equals or exceeds 50 percent of the market value of the building before the "start of construction" of the improvement. Substantial improvement includes buildings that have incurred "substantial damage," regardless of the actual repair work performed. Substantial damage reflects damage of any origin sustained by a building whereby the cost of restoring the building to its before-damaged condition would equal or exceed 50 percent of the market value of the building before the damage occurred.

11/1989

Effective November 1, new rules, which supersede those first implemented in October 1986, address provisions on the placement of manufactured homes in existing parks and subdivisions for manufactured homes. The revised rule is developed after consideration of recommendations by a task force including representatives of the manufactured home community and of state and local governments.

11/1989

The National Academy of Sciences completes Managing Coastal Erosion through the National Flood Insurance Program, a study requested by FIA, to provide advice on strategies for erosion management, supporting data needs, and applicable methodologies to administer these strategies through the NFIP. The study is necessary to determine whether the federal government should be involved in erosion insurance and, if so, how such a program should be administered. The question is triggered by the Upton-Jones Amendment (Section 544 of PL 100-242) to the National Flood Insurance Act of 1968 (see 5/1988).

11/1989

The Defense Production Act Amendment of 1989 (PL 101-137), which reauthorizes the NFIP, extends the Upton-Jones Amendment (see 5/1988) from September 30, 1989, through September 30, 1991, and requires FEMA to conduct a study to determine the impact of relative sea-level rise on FIRMs. The study will also project the economic losses associated with estimates of sea-level rise.

12/1989

FIA produces its first community Flood Risk Insurance Directory (FRID) as a prototype in conjunction with its program to digitize FIRMs. The FRID was never adopted because the information is available in the private sector.

Before 1989, FIA had maintained an archive of all effective and all previously effective NFIP maps in hard-copy paper format. To improve on the archival system, to reduce the storage required, and to make copies of the archived maps available to requestors, FIA begins microfilming all NFIP maps.

1989

The Association of State Floodplain Managers' first formal survey of state and local programs is completed. Using a standardized reporting form makes it possible to summarize state floodplain management activities at the end of the 1980s.

3/1990

FIA initiates the first two pilot erosion studies to develop the applicable methodologies and study processes to determine rates of erosion.

FIA institutes a map panel subscription service. This system allows subscribers to obtain current information on the status of NFIP maps, on a map panel-by-panel basis.

4/1990

The National Wildlife Federation sues FEMA, claiming that the NFIP facilitates development that may result in destruction or adverse modification of habitat of the key deer, an endangered species found only in the Florida Keys. The Endangered Species Act requires that all federal agencies ensure that the actions they authorize, fund, or implement do not jeopardize the continued existence of endangered species. To ensure compliance with this requirement, federal agencies must consult with the Secretary of the Interior about how such actions might affect endangered and threatened species or their critical habitats.

6/1990

C. M. "Bud" Schauerte is nominated to be Federal Insurance Administrator.

8/1990

The GAO reports on compliance with the mandatory flood insurance provision of the Flood Disaster Protection Act of 1973 (see 12/1973) in Information on the Mandatory Purchase Requirement. The GAO notes FEMA's belief that the level of compliance with the provision is low. In contrast, according to the GAO, several agencies with responsibility for enforcing the requirement state that noncompliance is not a major problem. GAO's own assessment identifies high levels of noncompliance in parts of the two states it examined, Maine (22 percent) and Texas (79 percent).

8/1990

Wallace E. Stickney is appointed FEMA Director.

9/1990

As of September 30, there are 2.3 million policies and more than $202 billion of coverage in force.

10/1990

The first financial statement audit of the NFIP that includes the WYO Program (covering 1986-89) results in an unqualified opinion.

10/1990

The Community Rating System (CRS) begins. Under CRS, discounts on flood insurance premiums are available in communities that voluntarily initiate activities that reduce flood losses or that increase the number of flood insurance policies.

10/1990 continued

CRS is the product of three years of development by the Community Rating Task Force, which had representatives from FIA, the insurance industry, and state and local floodplain managers. Extensive field testing, critiques, and reviews with communities, public interest organizations, and the Association of State Floodplain Management's technical advisors were conducted by the Insurance Services Office's Commercial Risk Services Organization under the technical directions of the Community Rating Task Force. Four hundred professional floodplain managers, 50 public interest organizations, and representatives of over 100 communities reviewed the proposal. CRS is also the subject of a congressional hearing.

10/1990

Effective October 1, the NFIP introduces new elevation and floodproofing for nonresidential structures certificates forms. In addition, the NFIP broadens the definition of a small business so that more businesses can qualify as small businesses under the program.

11/1990

The Omnibus Budget Reconciliation Act of 1990 (PL 101-508) requires FEMA to establish a policy fee to cover the administrative expenses, including salaries, and mapping expenses incurred in implementing the flood insurance and floodplain management program. The $25 fee (later increased to $30) applies to all new and renewal flood insurance policies sold after May 31, 1991. From 1987 to 1991, Congress required all program and administrative costs to be paid from the National Flood Insurance Fund (see 8/1968) without a commensurate increase in rates. FIA estimates that, as of September 2000, program assets were reduced by about $485 million because costs were not collected during these years.

11/1990

The Coastal Barrier Improvement Act of 1990 (PL 101-591) expands the Coastal Barrier Resources System (established by the Coastal Barrier Resources Act of 1982, see 10/1982) to include units along the Great Lakes, Puerto Rico, the Florida Keys, the Virgin Islands, and secondary barriers within large embayments. After a one-year grace period, federal flood insurance will be prohibited in these units as well as in "otherwise protected lands." Such public or private lands are held for conservation purposes.

After the law's passage, the Coastal Barrier Resources System includes approximately 1,200 miles of coastline and approximately 1,272,000 acres of undeveloped coastal barriers and associated aquatic habitats.

The Act directs the Secretary of the Interior to establish a Coastal Barriers Task Force, which would include a representative from FEMA. The task force is supposed to complete a report by November 1992 that, among other topics, identifies the number of structures for which flood insurance has not been available because of the Act. The report is never completed.

12/1990

Over 18,000 communities now participate in the NFIP. The Engineering Scientific Data Package System has archived almost 10,000 flood insurance studies. Since 1981, nearly 1,300 existing data studies or existing data restudies were produced using flooding information generated for other purposes. Since 1983, FIA has accredited more than 12,000 linear miles of levees that protect against 100-year floods.

1990

FEMA identifies seven states (Colorado, Illinois, Kansas, Missouri, North Dakota, Ohio, and Oklahoma) that had zoning exemptions in enabling legislation for agricultural buildings. Due to these exemptions communities could not enact ordinances in compliance with the NFIP. FIA worked with these states to pass legislation or obtain legal opinions that the communities had the authority to enact ordinances on floodplain management.

1/1991

The Mortgage Portfolio Protection Program (MPPP) begins. This voluntary program allows lenders to bring their portfolios into compliance with the requirements for the purchase of flood insurance. Any insurance purchased through this program would occur only if the mortgagor property owner does not respond to all the notices the program requires. Lenders participating in the MPPP can purchase policies (or “force place” required insurance coverage) at special high rates, reflecting the uncertainty as to the degree of risk due to the limited underwriting data required. Policies under the MPPP can be purchased only from WYO companies participating in the MPPP. Further, these policies can be purchased only as a last resort for properties that are part of a lending institution’s mortgage portfolio. The property must be located within a SFHA of a community participating in the NFIP and not be covered by a policy even after required notices have been given to the mortgagor property owner by the lending institution of the requirement for obtaining and maintaining such coverage.

3/1992

The Corps of Engineers publishes a revised Flood-Proofing Regulations.

7/1992

In Coastal Barriers: Development Occurring Despite Prohibitions against Federal Assistance, the GAO concludes that development continues on previously undeveloped barrier islands despite restrictions in the Coastal Barrier Resources Act (PL 97-348) on the issuance of flood insurance for structures on such islands. Equally important, the study finds that nearly 10 percent of residences in these areas have flood insurance coverage even though coverage is not supposed to be provided in these areas.

9/1992

In reviewing FEMA’s adherence to its policies for updating flood maps, the agency’s Office of Inspector General finds that FEMA does not consistently adhere to policies to ensure that restudies yielding the most benefits are performed first or use a standard set of criteria to choose maps to digitize. In addition, the Inspector General notes that FEMA provides information on communities to map users in five ways, with the result that the information from the different sources may conflict and lead to incorrect or unneeded flood insurance policies. FEMA generally agrees to implement the recommendations associated with the audit’s findings.

10/1992

Section 928 of the Housing and Community Development Act of 1992 (PL

102-550) legislates a flood-control restoration zone (AR) as a result of the decertification of the levee systems of Los Angeles and Sacramento, California. The Act makes certain insurance and development benefits available in areas where a federal flood-control system will be restored.

1992

A survey of state NFIP coordinators by the Association of State Floodplain Managers identifies an increase in state activities and state participants. The survey notes that many states participate in activities to restore and preserve the natural and cultural resources of floodplains and that many identify the environmental benefits of floodplain management as the key to obtaining wide public support. The survey reports that 39 states have more than 175 full-time equivalent personnel.

1992

The Federal Interagency Floodplain Management Task Force publishes its two-volume Floodplain Management in the United States: An Assessment Report. Key topics include individual risk awareness; migration to water; floodplain losses; short-term economic returns; enhanced knowledge and technology; national standards for flood protection; limited governmental capabilities; the need for interdisciplinary approaches; application of mitigation measures; the effectiveness of mitigation measures; the role of disaster relief; and national goals and resources. The report concludes that it is difficult to assess the effectiveness of floodplain management, observing that “there are few clearly stated, measurable goals,” and that “there is not enough consistent reliable data about program activities and their impacts to tell how much progress is being made in a given direction.”

2/1993

In Coping with Catastrophe: Building an Emergency Management System to Meet People’s Needs in Natural and Manmade Disasters, the National Academy of Public Administration concludes that, in light of the devastation caused by Hurricane Andrew in south Florida in 1992, FEMA has not successfully integrated its many missions. In the report’s words, “FEMA has been ill-served by congressional and White House neglect, a fragmented statutory charter, irregular funding, and the uneven quality of its political executives appointed by past presidents.”

4/1993

A U.S. District Court in Key West, Florida, hears the National Wildlife Federation’s complaint (see 4/1990) that the NFIP facilitates development in the Florida Keys that may jeopardize the continued existence of the key deer, an endangered species. In response, FEMA states that implementation of the NFIP is not an action subject to the consultation requirements of the Endangered Species Act.

6/1993

The Great Midwest Flood of the upper Mississippi and lower Missouri River basins from mid-June through early August provide evidence that the nation has not yet reached an accommodation between nature’s periodic need to occupy her floodplains and the present human occupancy and use. The floods generated the highest flood crests ever recorded at 95 measuring stations. President Clinton declares 505 counties in nine states to be federal disaster areas. Estimates of the total damage are as high as $16 billion. Only about one in ten of affected structures have flood insurance.

Various sources attempt to assign recurrence intervals (e.g., a “500-year” flood) to the flood, but they are subject to considerable error due to the flood’s complex and widespread nature, the short historic data record on which to base an analysis, changing observation methods, and the difficulty in assigning flow rates and elevations to past historic events. Stanley Changnon edits a comprehensive evaluation of this flood, The Great Flood of 1993: Causes, Impacts and Responses, which is published in 1996.

Four broad issues are examined as a result of this flood: a) whether to repair or reconstruct the hundreds of damaged flood-control levees (or other structural/protective measures in future floods) and who would pay for permitted repairs; b) whether to permit repair or rebuilding of thousands of substantially damaged structures so they could again be inhibited; c) whether to commit community planning and financial assistance to develop alternative mitigation strategies to the typical repair/rebuild scenario; and, d) whether to use the experience of risk insurance as a mitigation tool.

8/1993

To study the “levee issue” resulting from damage caused by the 1993 floods and to facilitate the search for appropriate alternatives, the Office of Management and Budget issues guidance to assess strategies for levee reconstruction. Representatives from five federal agencies, state and local governments, and other interested organizations consider alternatives to levee repair that would provide the benefits of flood control and protect natural resources. The committee affects decisions not to rebuild a few levees, but its overall impact is not felt until other post-flood recovery situations such as in California in 1995.

9/1993

The National Performance Review finds that the provision of federal disaster assistance is too generous and too frequent, with the possible result that the federal government may be perceived as the states’ “first-line resource in every emergency.” Echoing past recommendations (see 1/1981, for example), the Review urges the development of objective criteria to replace “political factors” in decisions about disaster declarations.

11/1993

In response to the criticisms contained in Coping with Catastrophe, FEMA reorganizes its 2,500 employees into five directorates, two administrations (the Federal Insurance Administration and the U.S. Fire Administration), and 10 regional offices.

12/1993

Due to extensive flooding during the previous fiscal year, the NFIP experiences losses that are more than twice its historic loss level and must borrow $100 million from the Department of Treasury to meets its needs for cash. This is the first time such borrowing has been necessary since 1984. The borrowed funds are repaid in FY 1994.

12/1993

The “Volkmer Amendment” in the Hazard Mitigation and Relocation Assistance Act of 1993 (PL 103-181) amends the 1988 Stafford Act (see 11/1988) to increase federal support for relocating flood-prone properties and to increase the amount of hazard-mitigation funds available after a disaster to 15 percent of all of FEMA’s appropriated federal disaster funds, up from 10 percent of a portion of FEMA’s funds dedicated to community assistance disaster funding for relocation or hazard-mitigation activities. The Act also increases to 75 percent from 50 percent, effective June 10, 1993, the share of the costs of mitigation activities the federal government will cover; clarifies acceptable conditions for the purchase of damaged homes and businesses; requires the complete removal of such structures; and dictates that the purchased land be dedicated “in perpetuity for a use that is compatible with open space, recreational, or wetlands management practices.”

1/1994

The Executive Office of the President, through the Administration Floodplain Management Task Force, assigns a broad mandate to the Federal Interagency Floodplain Management Review Committee to delineate the causes and consequences of the 1993 Midwest flooding and evaluate the performance of existing programs for floodplain and related watershed management.

The committee observes that "in the Midwest, the NFIP tends to discourage floodplain development through the increased costs in meeting floodplain management requirements and the cost of an annual flood insurance premium, although this may not be the case elsewhere in the nation."

1/1994 continued

The committee's report provides an opportunity for "a blueprint for change" in the nation's programs and policies affecting its coastal and riverine floodplains. The committee makes several recommendations including changes in federal policies, programs, and activities that will most effectively achieve risk reduction, economic efficiency, and governmental enhancement in the floodplain and related watersheds. In all, there are 93 recommendations to be used as "a blueprint for the future."

3/1994

The GAO issues Flood Insurance: Financial Resources May Not Be Sufficient to Meet Future Expected Losses. The report notes that income from insurance premiums is not sufficient to build reserves to meet expected flood losses. Consequently, the GAO concludes that losses from claims and the program's expenses will exceed the funds available to the program in some years.

4/1994

FEMA issues a proposed rule in response to the Housing and Community Development Act of 1992, which created a flood-control restoration zone (AR) designed to meet communities' concerns. The AR designation recognizes that a system for flood protection is being restored to provide protection during the base flood event and during the restoration period and reduces the costs of flood insurance and elevation requirements while still providing some level of protection for properties that will be exposed to the increased risks of flooding during the restoration period.

6/1994

The Interagency Floodplain Management Review Committee, given the responsibility for conducting a comprehensive review of floodplain management after the Midwest floods of the previous year, publishes Sharing the Challenge: Floodplain Management Into the 21st Century (sometimes referred to as the "Galloway Report," after the committee's chair, Gerald E. Galloway, Jr.). The report recommends a sharing of responsibility for floodplain management among federal, state, and local officials and for restrictions on development in floodplains.

With respect to flood insurance, the Committee criticized the limited penetration of the program in communities affected by the Great Midwest Flood of 1993 (see 6/1993). Repeating the warning of the National Performance Review (see 9/1993), the Galloway report notes that overly generous federal disaster assistance has the potential to reduce individuals' responsibility to protect themselves against disasters.

6/1994 continued

In addition, the report notes that the five-day waiting period between the time of purchase of a flood insurance policy and when coverage is effective allowed many people to purchase insurance with the knowledge that they would be flooded in the summer of 1993. If the waiting period had been 30 days, nearly

4,000 fewer insurance claims would have qualified, and payments would have been $82 million less. The committee thus recommended that the waiting period be increased to 15 days.

9/1994

The Community Development and Regulatory Improvement Act (PL 103-325), the National Flood Insurance Reform Act of 1994, includes the most comprehensive changes to the NFIP since the Flood Disaster Protection Act's approval in 1973.

Subtitle B provisions include a nonwaiver of the requirement that flood insurance be purchased by recipients of federal disaster assistance; expand requirements for lenders when making loans and requiring that coverage be maintained over the life of the loan; require escrow of flood insurance payments if escrows are already required; require placement of flood insurance by lenders if a borrower fails to obtain the necessary coverage; impose penalties for failure to require flood insurance or notify borrowers; impose fees for determining the applicability of flood insurance purchase requirement; establish notice requirements for properties located in a SFHA and a change in loan servicer; and require standard hazard determination forms.

Subtitle C codifies the Community Rating System and directs that credits may be given to communities that implement measures to protect natural and beneficial floodplain functions and manage erosion.

Subtitle D includes provisions to repeal the flood-property purchase and loan program (Section 1362); terminate the erosion-threatened structures program (Upton-Jones Amendment; see 5/1988 and 11/1989); establishes a Mitigation Assistance Program, which replaces the Upton-Jones acquisition/demolition program, to provide grants to states and communities based on a 75/25-percent cost share for mitigation plans and projects; creates the National Mitigation Fund; and provides additional coverage for compliance with land-use and control measures.

Subtitle E establishes the Flood Insurance Interagency Task Force (Section 561(a)) and the Task Force on Natural and Beneficial Functions of the Floodplain. The Flood Insurance Interagency Task Force is directed to conduct a number of studies addressing the programs and procedures of Federal agencies and corporations for compliance with NFIP regulations, and to submit a report of findings and conclusions to Congress.

9/1994 continued

Subtitle F increases the maximum coverage amounts available and includes a requirement to review and assess the need to update and revise FIRMs every five years; establishes a Technical Mapping Advisory Council; requires a study of the economic impacts of erosion-hazard areas; requires an economic impact study of the effect of charging actuarial rates for pre-FIRM properties; increases the waiting period for flood insurance policies to 30 days (see 6/1994); adds provisions regarding agricultural structures; and prohibits disaster assistance to individuals in a SFHA who received disaster assistance and did not maintain flood insurance.

9/1994

In an Audit of FEMA's Mitigation Programs, FEMA's Inspector General concludes that a lengthy application process, due primarily to the significant delays in the process for determining project eligibility, hampers the agency's implementation of the Hazard Mitigation Grant Program (see 11/1988). In the audit's words, "The criteria for determining environmental impact, cost effectiveness and whether projects represent a long-term solution are especially confusing." In addition, the audit concludes that "there are no mechanisms to measure the effectiveness of mitigation in any of FEMA's programs, and managers have neither the qualitative tools nor resources."

10/1994

FIA issues a newly revised Agent Flood Insurance Manual.

11/1994

Given the gravity of the 1993 Midwest flood and because less than 15 percent of the nonfederal levees that were damaged qualified for repair consideration under the Corps of Engineer's emergency flood-control repair program, Congress provides supplemental funding for repair of levees. Under the authority of PL 84-99, the Corps of Engineers rehabilitate the 115 levees already eligible under its program and another 241 nonfederal levees using supplemental funding. In total, repairs cost $230 million.

12/1994

The number of flood insurance policies in force exceeds three million for the first time.

12/1994

A report issued by the U.S. House of Representatives Bipartisan Natural Disasters Task Force concludes that the federal government's generosity with disaster assistance diminishes the incentives for state and local governments "to spend scare state and local resources on disaster preparedness, mitigation, response, and recovery. This not only raises the costs of disasters to federal taxpayers, but also to our society…as people are encouraged to take risks they think they will not have to pay for."

The Task Force recommends the creation of a "private, naturally based all-hazard insurance program, in consultation with the insurance industry…for residential and commercial property."

1994

A revised Unified National Program for Floodplain Management is published. In the report, the Federal Interagency Floodplain Management Task Force recommends four broad goals for a Unified National Program. These are to: formalize a national goal-setting and monitoring system; reduce by at least half the risks to life and property and the risks to natural resources of the nation's floodplains; develop and implement a process to "encourage positive attitudes toward floodplain management;" and establish a nationwide, in-house capability for floodplain management.

The report, submitted to Congress on March 6, 1995, also identifies objectives necessary to achieve each goal and establishes target dates for completing them.

1994

The Federal Interagency Floodplain Management Task Force, with funding from the Environmental Protection Agency and the Corps of Engineers, publishes a guidebook for community officials and other interested parties to aid in developing local programs to protect and restore important floodplain resources and functions. Protecting Floodplain Resources: A Guide for Communities provides information on methods to mitigate flood hazards to preserve the integrity of natural systems.

1994

The Association of State Floodplain Managers produces National Flood Programs in Review, 1994, the Association's first comprehensive effort to assess national programs and policies related to floodplain management.

1994

Elaine A. McReynolds is appointed Federal Insurance Administrator.

1994

In Florida Key Deer v. Stickney, 864 F. Supp. 1222 (S.D. Fla. 1994), a U.S. District Court rules that FEMA must comply with the requirements of the Endangered Species Act and consult with the Department of the Interior regarding the possible impacts of development by flood insurance on the key deer, and endangered species (see 4/1990 and 4/1993).

1/1995

As a result of an Audit of the Accuracy of Flood Zone Ratings, FEMA's Inspector General finds that zone misreadings occurred in more than one-quarter of all flood insurance policies and that premiums were incorrect for 10 percent of the policies sampled. The audit also notes that FEMA's flood maps are difficult to read, that the rules for writing policies are more complex than for most other forms of insurance, and that FEMA does not have a program for quality control to verify that insurance agents use the correct rating factors (such as flood zone, elevation, or pre- or post-FIRM status) to calculate premiums.

FEMA accepts the findings, but does not act to implement the report's recommendations, at least through the end of 1999.

2/1995

Retroactive to September 23, 1994, (the date President Clinton signed PL 103-325, the National Flood Insurance Reform Act), all applicants for Individual and Family Grants (IFG) who receive federal disaster assistance are required to purchase and maintain flood insurance on the flooded property until they move to another address. Failure to maintain the insurance will preclude receipt of any subsequent disaster assistance through the IFG program.

2/1995

FEMA publishes in the Federal Register the first compendium that lists all revisions and amendments made to flood maps between October 1, 1994, and December 31, 1994. Subsequent compendia are published in the Federal Register every six months.

3/1995

Federal Disaster Assistance, Report of the Senate Bipartisan Task Force on Funding Disaster Relief (U.S. Senate Doc. No 104-4) concludes that Congress should improve financial preparedness for catastrophic events. The report notes that between FY 1977 and 1993, the federal government spent $64 billion in direct disaster relief and $55 billion indirectly through low-cost loans.

Congress does not act on the recommendations. The Task Force recommends: a) clarification of criteria for declarations of disasters; b) improved incentives for mitigation; and c) greater dependence on insurance. The Senate Task Force does not support the recommendations of the House Bipartisan Natural Disasters Task Force (see 12/1994) regarding all-hazard insurance.

3/1995

FIA proposes the creation of Group Flood Insurance Policies (GFIP). Such policies, intended for low-income recipients of flood-related disaster assistance through the NFIP's Individual and Family Grant Program (see 2/1995), will provide three years of flood insurance, with the federal (75 percent) and state governments (25 percent) sharing the cost of the premiums. At the end of the three-year period, each GFIP recipient will be required to purchase and maintain a standard flood insurance policy. Coverage on that property must be continued as long as the property exists.

3/1995

In response to the National Flood Insurance Reform Act of 1994, FEMA increases the waiting period to 30 days from 5 days before flood insurance coverage becomes effective. Two exceptions are possible: when the initial purchase of flood insurance is in connection with the making, increasing, extension, or renewal of a loan and when the initial purchase of flood insurance occurs during the one-year period following notice of the issuance of a revised FIRM for a community.

7/1995

Effective July 1, the NFIP introduces provisional ratings for policies that require an elevation certificate when it is not yet available. The NFIP begins accepting credit cards as a means of paying insurance premiums.

7/1995

The Corps of Engineers publishes Floodplain Management Assessment of the Upper Mississippi River and Lower Missouri Rivers and Tributaries. Among its findings, the Corps determines that structural flood protection prevents significant damage, that restoration of floodplain wetlands would have had little impact on floods the size of those in 1993, and increased reliance on flood insurance better ensures appropriate responsibility for flood damage.

7/1995

FEMA's Inspector General issues an Audit of the Enforcement of Flood Insurance Purchase Requirements for Disaster Aid Recipients. The audit finds that individual recipients of flood-related disaster assistance, who are required to purchase and maintain flood insurance if their flood-damaged property is insurable and within a SFHA, often do not do so (see 9/1994). Low levels of compliance are found even though grants through the Individual and Family Grant Program include funds for the first year's premium.

Similarly, the audit notes "very low" levels of compliance with the mandatory-purchase requirement among recipients of grants from FEMA's Public Assistance Program. Such grants provide funds for the repair of state and local governments' facilities. Recipients of Public Assistance funds must purchase flood insurance if their flood-damaged property is insurable and if their grant is over $5,000, regardless of whether the property is in a SFHA if insurance is reasonably available, adequate, and necessary.

9/1995

Due to extensive flooding during the previous 12 months, the NFIP experiences losses that are much higher than the historic loss level and must borrow $265 million from the Department of Treasury to meets its needs for cash.

10/1995

The NFIP's "Cover America" campaign begins. The campaign represents a nationwide effort to increase public awareness of the perils of flooding and the desirability of purchasing flood insurance.

12/1995

FEMA issues The National Mitigation Strategy: Partnerships for Building Safer Communities. The document emphasizes two key goals, increasing public awareness of the risks associated with natural hazards and significantly reducing the loss of life, injuries, economic costs, and disruption of families and communities due to natural hazards.

1995

A survey of states by the Association of State Floodplain Managers describes trends since 1992 that have reversed some of the continuous advances made since the late 1960s. According to the survey, state programs face challenges in budget, organization, and authority that threaten their ability to be full, active partners with the federal government and local communities in reducing flood losses. The report concludes that states' capabilities have eroded because of legislative dilution, budgetary restrictions, and organizational dissection.

1/1996

Federally regulated lenders, federal agency lenders, and government-sponsored enterprises are henceforth required to use the Standard Flood Hazard Determination Form. This form is used to determine whether real property offered as collateral for a loan is located in a SFHA.

2/1996

President Clinton promotes FEMA's director to cabinet status.

4/1996

Effective April 30, the NFIP revises the standard flood insurance application and endorsement forms and makes them available through ACORD, a non-profit association that develops and maintains communication standards for the insurance industry.

5/1996

FEMA initiates the use of Group Flood Insurance Policies (see 3/1995). Such policies help disaster victims located in a SFHA who do not qualify for loans from the Small Business Administration comply with flood insurance purchase requirements. The first such policies are issued in August 1996.

8/1996

Federal regulators of financial institutions issue a joint rule on August 29 to implement the provisions of the National Flood Insurance Reform Act of 1994. The rule is intended to achieve uniformity among these regulators on the substantive and procedural requirements of the act. These regulations become effective on October 1, 1996.

9/1996

FEMA exempts several categories of projects funded through the Stafford Act's Hazard Mitigation Grant Program (see 11/1988) from the use of a benefit-cost analysis due to the difficulty in quantifying known project costs and the time involved in gathering data. Exempted activities include those in which the cost of restoring damaged structures equals or exceeds 50 percent of the structures' market value and the structures are located in a 100-year floodplain.

9/1996

In response to Section 541 of the National Flood Insurance Reform Act of 1994, FEMA submits The Community Rating System of the National Flood Insurance Program to Congress. The section requires FEMA to submit a report on the rating system to Congress every two years. Such reports are required to analyze the program's cost effectiveness, accomplishments, or shortcomings, and to provide recommendations for legislation.

9/1996

Due to extensive flooding during the past 12 months, the NFIP experiences losses that are much higher than its historic loss levels and must borrow funds from the Department of Treasury to meets its needs for cash. The total amount borrowed reaches $626 million. The NFIP borrows an additional $192 million over the next six months.

10/1996

Congress approves a supplemental request (reflected in PL 104-208) to increase the NFIP's borrowing authority (see 9/1996) for FY 1997 to $1.5 billion from $1 billion.

10/1996

Federally regulated lending institutions and government-sponsored enterprises (GSE) that purchase mortgages are required, effective October 1, to escrow premiums for flood insurance for properties located in floodplains. If a federally regulated lender or GSE determines that a property in a SFHA does not need flood insurance, such insurance can be "force placed" at the borrower's expense.

10/1996

The Federal Financial Institutions Examination Council (FFIEC) implements revised examination procedures for flood insurance in response to the new mandatory purchase requirements of the National Flood Insurance Reform Act of 1994 (see 9/1994).

12/1996

FEMA issues interim guidance for determining the cost-effectiveness of hazard-mitigation projects entitled How to Determine Cost-Effectiveness of Hazard Mitigation Projects: A New Process for Expediting Application Reviews. The new guidelines declare that benefit-cost analysis should be used for all cost-effectiveness determinations.

12/1996

Through its Innovations in American Government program, Harvard University's School of Government recognizes FEMA for its Consequent Assessment Tool Set (CATS), which enables the agency to predict the likely consequences of an impending disaster and then to rapidly mobilize an appropriate response.

12/1996

FEMA creates an Insurance Task Force to develop recommendations for the reform of its Public Assistance program (see 11/1988 and 7/1995). The Flood Disaster Protection Act of 1973 required the NFIP to identify, by June 30, 1974, all communities that contain areas at risk for serious flood hazard and to notify these communities that they can apply for participation in the NFIP or forego their eligibility for certain types of federal assistance in their floodplains (see 12/1973).

1996

The Association of State Floodplain Managers establishes an executive office in Madison, Wisconsin. The Association has catalogued more than 700 publications, which are housed at the National Floodplain Management Resource Center at the University of Colorado.

1996

Gerald Galloway declares "the flood [the 1993 upper Mississippi and lower Missouri River basins flood] is over. No one now cares," in his remarks to the Association of State Floodplain Managers Annual Conference and printed in National Flood Policy: Progress Since the 1993 Floods.

1/1997

FEMA's Insurance Task Force issues Insurance Regulations, Review, Analysis, and Recommendations. The report focuses attention on FEMA's Public Assistance program and recommends that: a) insurance deductibles not be eligible for FEMA funding; b) FEMA establish a policy requiring actual proof of insurance rather than an insurance commitment, before funding is provided; c) FEMA should develop clear regulations to minimize opportunities for misinterpretation of these regulations among FEMA's regional offices; and d) the authority of state insurance commissioners to waive insurance requirements for public facilities be revoked. In lieu of these commissioners being allowed to grant waivers, the report encourages input from them as to the availability, adequacy, and necessity of insurance. Under no circumstances, however, should the requirement be waived because of affordability, at least according to the report.

3/1997

FEMA issues a Report on Costs and Benefits of Natural Hazard Mitigation, which reviews the benefits of mitigation measures. Among the report's 16 case studies are three related to floods: a) the acquisition and relocation of floodplain structures in Missouri; b) land-use and building regulations along Florida's coasts; and c) land-use and building requirements in floodplains.

3/1997

The Flood Insurance Interagency Task Force submits an interim report to Congress providing details on surveys, studies, and research underway to complete the tasks directed by Title V of the National Flood Insurance Reform Act of 1994 (see 9/1994).

5/1997

To consider and implement the recommendations in the 1994 report, A Unified National Program for Floodplain Management, FEMA convenes a group of about 40 experts at the annual conference of the Association of State Floodplain Managers in Little Rock, Arkansas and prepares a report on the forum.

6/1997

Mandated by the National Flood Insurance Reform Act of 1994, Increased Cost of Compliance (ICC) coverage is included in all new and renewed flood insurance policies effective on or after June 1, 1997. This coverage helps to cover the costs of bringing flood-damaged homes and businesses into compliance with community floodplain ordinances. The coverage limit of $15,000 helps to pay for elevating, flood proofing, demolishing, or relocating a structure that has been substantially or repetitively damaged by flooding. ICC coverage is available only in communities that adopt and enforce substantial-damage or repetitive-loss provisions in their floodplain management ordinances and require action by property owners.

9/1997

In accordance with the Government Performance and Results Act (PL 103-62), FEMA issues its first strategic plan, Partnership for a Safer Future. The plan delineates FEMA's mission statement, which is to reduce future loss of life and property through timely delivery of assistance intended to help communities restore damaged services and rebuild facilities. According to the plan, FEMA seeks to reduce, by FY 2007, the risk of loss of life and injury from natural hazards by 10 percent and the risk of property loss and economic disruption from such hazards by 15 percent.

9/1997

Due to continuing flood-related losses that exceed historical averages, the value of the Department of the Treasury's loans to the NFIP reach $917 million (see 9/1995 and 9/1996).

10/1997

FEMA publishes a final rule on AR Zones. The rule establishes an AR zone or area of special flood hazard that results from the decertification of a previously accredited flood protection system that is determined to be in process of being restored to provide base flood protection.

10/1997

FEMA begins "Project Impact," an effort to protect against the impact of natural disasters before they happen. The project seeks to build disaster-resistant communities through public-private partnerships and includes a national public-awareness campaign; the designation of pilot communities; and an outreach effort to community and business leaders. FEMA will encourage communities to assess the risks they face, to identify their vulnerabilities, and to take steps to prevent disasters.

The first three pilot communities include Deerfield Beach, Florida; Pascagoula, Mississippi; and Wilmington, North Carolina. Others are in California, Maryland, Washington, and West Virginia. FEMA's goal is to have at least one Project Impact community in every state by September 30, 1998.

Congress appropriates $30 million for Project Impact for FY 1998 and $25 million for the following fiscal year.

10/1997

FEMA announces that benefit-cost analyses will not be required for hazard mitigation planning projects associated with disasters that occurred before June 10, 1993.

11/1997

In Modernizing FEMA's Flood Hazard Mapping Program, FEMA describes its plans to modernize its flood-hazard maps, of which there are about 100,000 map panels. The program's purpose is to increase public awareness and the maps' accuracy, utility, and production. Approximately 45 percent of the current maps are at least 10 years old, and 70 percent are five years or older. Consequently, many of the maps are inaccurate and portray analyses that are outdated.

11/1997 continued

FEMA estimates the cost of implementing its new program at $901 million (in addition to the $46 million spent in 1997) over seven years. FEMA believes that the plan will avoid approximately $26 billion in flood damages to new buildings over a 50-year period.

12/1997

In response to Section 577 of the National Flood Insurance Reform Act of 1994, FEMA completes a process of mapping erosion hazards in 27 coastal counties in 18 states.

1997

The Association of State Floodplain Managers establishes a foundation to "attract funds that support, through education, training and public awareness, projects and programs that will lead to the wise management of our nation's floodplains."

1997

The Presidential Long Term Recovery Task Forces (for the 1997 Red River floods) are established. These task forces operate at a higher administrative level and are more visible than FEMA's mitigation process. Recovery and mitigation become increasingly integrated.

1997

FEMA awards a contract to evaluate the NFIP's underwriting and loss adjustment process. This subsequent report provides recommendations to improve the operation of the NFIP by identifying practical changes to the underwriting/rating and claims processes. The NFIP's requirements and controls (and compliance with them) are found to be adequate to ensure effective management of the program. The report also notes areas for improvement.

1997

FEMA awards a contract to investigate alternative financing arrangements for the NFIP. A stochastic model is developed to estimate the NFIP's financing costs over a ten-year period using eight alternative financing scenarios. Four commercial and four governmental financing scenarios are simulated, and the total cost of each is projected.

1/1998

FEMA initiates the Repetitive Loss Task Force to develop a strategy to address the NFIP's repetitive loss problem.

3/1998

The American Society of Civil Engineers releases its 1998 Report Card for America's Infrastructure and declares that "an alarming number of dams across the country are showing signs of age and lack of proper maintenance….Dam safety officials estimate that thousands of dams are at risk of failing or are disasters waiting to happen."

3/1998

FEMA's Office of Inspector General issues Review of FEMA's Implementation of Insurance Requirements in the Public Assistance Program. The report recommends that FEMA clarify its regulations governing the conditions under which state insurance commissioners issue waivers of insurance requirements for recipients of Public Assistance grants.

As a condition of receiving a Public Assistance grant, FEMA requires that applicants purchase and maintain insurance on property damaged in a disaster (see 11/1988, 1/1997, and 7/1995). The amount of insurance applicants must purchase is equal to the cost of repairs to the property. In addition, insurable structures located in a SFHA must be insured if they have been damaged in previous disasters. These requirements are designed to reduce the need for future disaster assistance. In lieu of a commitment to purchase insurance, an applicant can obtain a waiver from a state insurance commissioner. The commissioner can waive the requirement if it is determined that the required insurance is not reasonably available, adequate, and necessary.

The Inspector General's report notes that FEMA has not provided an interpretation of what is reasonable, with the consequence that many waivers are granted because insurance commissioners decide that suitable coverage is not affordable. In such instances, FEMA has a substantial uninsured investment since it is the primary insurer.

3/1998

In a separate report, Improvements Are Needed in the Hazard Mitigation Buyout Program, the Office of Inspector General questions FEMA's decision to exempt certain categories of activities from the requirement that mitigation activities be cost-effective, as determined through the use of cost-benefit analysis. The report also notes that FEMA lacks an analytical basis for exempting such projects.

5/1998

On May 1, the NFIP increases the standard deductibles for building and contents coverages for subsidized policies to reduce the subsidy levels through means other than rate increases. Other program changes include: new eligibility requirements for Preferred Risk Policies based on the flood history of the property regardless of ownership, implementation of new AR zones, and detailed procedures for detailed procedures for determining eligibility for NFIP insurance in areas of the Coastal Barrier Resources Systems.

6/1998

The National Flood Determination Association (NFDA) incorporates itself. The NFDA, a national non-profit organization, promotes the interest and success of companies involved in making, distributing, and reselling flood zone determinations.

9/1998

FEMA initiates a nationwide Call for Issues. Through this activity FEMA requests comments on all facets of the NFIP from its partners and customers in an effort to improve the program's effectiveness.

9/1998

The Flood Insurance Interagency Task Force submits its final report to Congress on Enforcement and Compliance Procedures Necessary to Carry Out the Provisions of the National Flood Insurance Reform Act. The Task Force reports on its development of a compliance model checklist, a catalog of compliance assistance materials, and a list of "best practices" for federal agencies and Government Sponsored Enterprises (GSEs). The report finds that a reasonable degree of standardization of enforcement exists within the federal agencies and GSEs.

9/1998

Five cities in southern California file a lawsuit in U.S. District Court in which they claim that FEMA's delineation of a flood control restoration zone (Zone AR) violates the National Environmental Policy Act and Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The cities allege that the zone's designation and the requirements it imposes will have a substantial negative impact of their residents' ability to use their land, on the environment, and on minority and low-income populations.

10/1998

The Partnership for Response and Recovery, under a FEMA contract, issues Analysis of Public Assistance Proposed Insurance Regulation Changes, which estimates the potential cost reductions of proposed changes in insurance regulations and the Stafford Act's Public Assistance grants (see 11/1988, 7/1995, 1/1997, and 3/1998).

10/1998

In response to Section 541 of the National Flood Insurance Reform Act of 1994, FEMA completes and submits to Congress An Evaluation of the National Flood Insurance Program's Community Rating System. The report notes that 894 communities, representing 66 percent of all policyholders, participate in CRS (see 10/1990 and 9/1994). Tulsa, Oklahoma, and Sanibel Island, Florida, are the two-best rated CRS communities.

11/1998

FEMA's director, James Lee Witt, announces a series of proposals to reduce disaster losses by half in three years and to save nearly $1 billion over 10 years. If adopted, the first proposal would prohibit the purchase of flood insurance by homeowners who have filed two or more claims that total more than the value of their home and who refuse to elevate their home or to accept a buyout. At present, there is no limit to the number of claims made by property owners who suffer repetitive damage from floods.

11/1998 continued

The second proposal would require that public buildings be insured to 80 percent of their replacement value within two years. Although the 1988 Stafford Act requires states and local communities to insure public buildings, FEMA's regulations require only that the amount of insurance to be purchased must be at least up to the amount of eligible damage under the Public Assistance program (see 11/1988, 7/1995, 1/1997, and 3/1998). If the eligible damage is less than the building's replacement value, and if the corresponding minimal levels of insurance can be purchased, this can result in vastly underinsured buildings.

Existing regulations do not indicate whether the insurance must provide coverage for a building's actual cash value or its replacement cost and do not address deductibles. Consequently, the current regulations do not include any incentive to encourage insurance on public buildings that have benefited from disaster assistance.

1998

FIA estimates that approximately 1.7 million homeowners (or 38 percent) with a mortgage in a SFHA do not have flood insurance.

1998

The National Wildlife Federation publishes Higher Ground: A Report on Voluntary Property Buyouts in the Nation's Floodplains describing efforts to restore floodplains through voluntary buyouts of property in high-risk areas. The report analyzes repetitively flooded properties and discusses the history of buyout programs in the United States and the 1993 Midwest flood. Most important, the report concludes that the NFIP is not actuarially sound and that its premiums are insufficient to generate the funds needed to cover flood insurance payments.

1998

JoAnn Howard is appointed Federal Insurance Administrator.

1/1999

The Association of State Floodplain Managers supports the creation of state floodplain management associations and encourages their chapter membership. As of 1999, 12 states enjoyed chapter membership. Several other states formed associations, with many working toward chapter status.

1/1999

FIA uses findings from an evaluation of the "Cover America" campaign to develop the "Cover America II" campaign.

1/1999

FEMA, working with the Public Risk Management Association, conducts a series of regional meetings of public risk managers to discuss and hear reactions to FEMA's first draft of its insurance proposal relative to Public Assistance grants under the Stafford Act (see 11/1988, 7/1995, 1/1997, 3/1998, and 11/1998). FEMA's goal is to limit funding under the Act's Public Assistance program to the state and local agencies that maintain specified minimum levels of insurance coverage. FEMA believes that existing rules create a disincentive to both carry insurance and to manage the risk of disasters and are inequitable in that they penalize state and local governments that purchase appropriate insurance coverage.

1/1999

National Flood Insurance Program: Issues Assessment, A Report to the Federal Insurance Administration is published. This report, funded by FEMA, is based on a literature review to answer questions about the program's effectiveness by assessing two central concerns: the relation between floodplain development and insurance availability and enforcement of floodplain management requirements at the local level. The report notes that "none of the studies offered irrefutable evidence that the availability of flood insurance is a primary factor in floodplain development today. Neither does the empirical evidence lend itself to the opposite conclusion." Noting that "it is there, in the day-to-day decisions by location officials, that the [NFIP] either succeeds or fails to accomplish its statutory mandate" and that "a number of tools and oversight systems have been devised to monitor, support and evaluate the quality of community enforcement." The report offers no conclusions regarding the second concern.

1/1999

FEMA requests that Congress authorize a transaction fee of $15 for each federally insured mortgage issued. The money collected will be used to fund FEMA's modernization of its maps. Congress eventually declines the request but does provide $5 million to begin updating the maps.

The U.S. Senate Committee on Appropriations instructs FEMA to evaluate alternative funding options. FEMA's response is contained in Flood Map Modernization Plan: Funding Options Report. Four options are identified: a map-use fee; an increase in the fee charged for each flood insurance policy; supplemental appropriations; and use of the NFIP's borrowing authority.

2/1999

The U.S. House of Representatives' Committee on Financial Services indicates that its oversight plan for the 106th Congress includes attention to repetitive losses and the implementation of the Community Development and Regulatory Improvement Act of 1994 (see 9/1994).

3/1999

To recognize the inherently greater flood risk of pre-FIRM, V-zone properties, FIA announces increases in the amount of premiums that flood insurance policyholders must pay for flood insurance coverage for pre-FIRM buildings in coastal areas subject to high velocity waters, such as storm surges and wind-driven waves.

4/1999

FIA hires an advertising agency to plan, implement, and evaluate the five-year "Cover America II" campaign. A new logo is developed for the campaign.

5/1999

On May 1, the NFIP eliminates the three-year policy.

5/1999

At FEMA's request, a Study of the Economic Effects of Charging Actuarially Based Premium Rates for pre-FIRM Structures is completed. The study examines: the number and types of properties that would be affected by an increase in premium rates; the number of policyholders that might cancel their policies if rates are increased; and the effects of increased premiums on property taxes and the value of land. The report estimates that there are about seven million structures in a SFHA. The study concludes that an immediate elimination of subsidized flood insurance would lead to a significant drop in the number of people retaining insurance. In the report's words, "…if [the] subsidy was eliminated…average premiums for residential properties subject to substantial flood risk would likely increase from $585 to about $2,000 annually."

5/1999

The Association of State Floodplain Managers initiates a Certified Floodplain Manager (CFM) Program. The program is intended to advance the knowledge of floodplain managers, enhance the profession of floodplain management, and provide a common basis for understanding floods and flood losses.

5/1999

A. U.S. District judge in the Central District of California rules that FEMA did not violate the National Environmental Policy Act by requiring flood insurance of property owners in five southern California cities without first preparing an environmental impact statement (see 9/1998).

6/1999

The Board of Governors of the Federal Reserve System imposes the first penalty on a federally regulated lending institution, in Puerto Rico, for a pattern of noncompliance with the mandatory-purchase requirement of the Flood Disaster Protection Act of 1973. The Federal Deposit Insurance Corporation subsequently imposes a fine on a lending institution for the same reason.

7/1999

FEMA submits a draft, revised regulation on Public Assistance grants and insurance requirements to the Office of Management and Budget for review and approval (see 11/1988, 7/1995, 1/1997, 3/1998, 11/1998, and 1/1999). FEMA designates the draft proposed rule as being economically significant under Executive Order 12866, Regulatory Planning and Review, but has not yet completed analyses of the economic impact the proposed regulations would have on small entities.

7/1999

With the imminent expiration of the first Group Flood Insurance Policies (see 5/1996 and 8/1996), FEMA extends the coverage of such policies from 36 to 37 months. As of September 30, 2002, FEMA reinstates the 36-month term for Group Flood Insurance Policies.

8/1999

FEMA proposes to apply full-risk premium rates on new or renewed policies for structures that have suffered multiple flood losses whose owners have declined an offer of funding to elevate, relocate, or flood proof the structure. Labeled as "target repetitive loss buildings," these structures have had two or more flood-related losses, each resulting in a claim of $1,000 or more, within the past 10 years. In addition, such structures have suffered four or more insured flood losses or two insured flood losses cumulatively greater than their value.

FEMA indicates that approximately 8,000 insured structures have suffered four or more losses; another 1,300 insured buildings have had two or three losses that cumulatively exceed their value.

8/1999

The GAO releases Disaster Assistance: Opportunities to Improve Cost-Effectiveness Determinations for Mitigation Grants. The 1988 Stafford Act requires that such grants be cost effective, but the report notes that 15 percent of funds distributed by FEMA’s Hazard Grant Mitigation Program have been exempted from benefit-cost analysis or had a benefit-cost ratio of less than 1.0. In addition, 39 percent of projects had a benefit-cost ratio of between 1.0 and 1.5, and were thus “marginally effective,” at least according to a subcommittee of the U.S. House of Representatives’ Committee on Transportation and Infrastructure.

FEMA states that it will comply with all of the recommendations included in the GAO report.

8/1999

FEMA issues Cost Estimate for the Flood Map Modernization Plan. The report estimates it will cost $750 million to implement the plan over the seven-year period from FY 2001-07. The upgrade of the map inventory will involve updating and producing digital maps for at least 17,500 panels requiring updates, digital conversion and maintenance for 74,500 panels, and development of flood data and digital flood maps for 13,700 panels for flood-prone communities without flood maps.

9/1999

In an Audit of the Effectiveness of the Substantial Damage Rule, FEMA’s Inspector General notes that many communities participating in the NFIP fail to enforce the substantial damage rule. As a result, subsidized rates are provided to structures that should be rated on an actuarial basis.

9/1999

FEMA publishes an Economic Evaluation of Substantially Damaged Structures Funded through the Hazard Mitigation Grant Program. The report retrospectively calculates the costs and benefits of approximately 10 percent of acquisition and relocation projects for substantially damaged structures in floodplains.

9/1999

Hurricane Floyd strikes North Carolina and causes the worst flooding in the state’s history. Over $100 million in disaster assistance is provided to more than 72,000 residents.

Throughout the state, nearly 150,000 structures are located in SFHAs, but only one-third are covered by flood insurance.

10/1999

FEMA’s director hosts a meeting with insurance executives. According to FEMA, the participants agree that FEMA’s proposal on Public Assistance grants has strong merit and the amount of insurance coverage appears reasonable (see 11/1988, 7/1995, 1/1997, 3/1998, 11/1998, and 1/1999). FEMA also observes that doubt is expressed about the market’s ability to provide earthquake coverage immediately and that several meeting participants suggested separating earthquake insurance from the proposal.

10/1999

FIA begins operating the Special Direct Facility (SDF) to centralize policies with repetitive losses for control purposes and mitigation actions. Two subsets of currently insured repetitive-loss properties are moved to the SDF – those with two or three paid losses where the cumulative payments for flood insurance claims are equal to or greater than the building value and those with four or more paid losses.

10/1999

FEMA director James Lee Witt informs a congressional committee that 84 percent of the agency's flood-hazard maps are more than five years old, 66 percent are greater than 10 years old, and 33 percent are greater than 15 years old. Some maps, produced in the 1970s, have never been updated.

10/1999

At a hearing before the U.S. House of Representatives' Subcommittee on Housing and Community Development Opportunity of the Committee on Banking and Financial Services, Director Witt notes that FEMA has identified approximately 10,000 properties that have had four or more flood losses or two or three flood losses that cumulatively exceed the value of the building. The NFIP has provided over $800 million in claims for these properties over the past 21 years. The total cost for mitigation or buyout for these structures would be about $450 million.

10/1999

Through October 1999, FEMA has issued 98 Group Flood Insurance Policies (see 3/1995, 5/1996, 8/1996, and 7/1999) covering nearly 29,000 households.

11/1999

The H. John Heinz III Center for Science, Economics and the Environment publishes The Hidden Costs of Coastal Hazards. The result of a two-year study by an expert panel, the report suggests new strategies to identify and reduce weather-related hazards and the costs associated with rapidly increasing coastal development. The report offers the first in-depth estimates of the costs of coastal hazards to natural resources, social institutions, business, and the built environment.

11/1999

"Cover America II" begins to increase awareness of the NFIP and flood insurance.

11/1999

The Consolidated Appropriations Act (PL 106-113) directs FEMA to study the feasibility and justification for reducing buyout assistance to property owners who fail to purchase and maintain flood insurance. The Act also authorizes up to $215 million for the buyout or relocation of owner-occupied principal residences located in a 100-year floodplain that were made uninhabitable by flooding caused by Hurricane Floyd and "surrounding events" in October 1999. Before such funds can be allocated, FEMA will be required to establish procedures for establishing priorities and for benefit-cost analyses.

12/1999

By the end of 1999, there are more than 4.2 million flood insurance policies in effect, with total insurance coverage of more than $534 billion, an increase of more than 250 percent since December 1990.

1999

Approximately 20 years after publication of the first Assessment of Research on Natural Hazards, researchers complete a follow-up study to reassess the state of knowledge of natural hazards in the United States. Begun in 1992, the study involves more than 120 experts and culminates in Disasters by Design:

A Reassessment of the Natural Hazards in the United States. The report concludes that: a) one of the central problems in coping with disasters is the belief that technology can be used to control nature; b) most strategies for coping with hazards fail to consider the complexity and changing nature of hazards; and c) losses from hazards result from shortsighted and narrow concepts of the relation of humans to the natural environment. To redress these shortcomings, the researchers recommend that the United States shift to a policy of "sustainable hazard mitigation." This concept links wise management of natural resources with local economic and social resiliency.

1999

In Disasters and Democracy: The Politics of Extreme Natural Events, Rutherford Platt and his colleagues trace the historical evolution of the federal role in disaster assistance and analyze disaster declarations and federal assistance provided under the Robert T. Stafford Relief and Emergency Assistance Act since 1988.

End 1990s

FEMA has mapped more than 100 million acres of SFHAs and had designated about six million acres of floodways along 40,000 stream and river miles. The total cost for these studies is approximately $1.3 billion.

1/2000

The International Building Code and the International Residential Code are published. For the first time there is a national model building code that includes the construction provisions of the NFIP. The codes are substantially equivalent to the requirements of the National Earthquake Hazard Reduction Program Recommended Provisions (1977) and the state-of-the-art wind-load provisions of the American Society of Civil Engineers (1998), Minimum Design Loads for Buildings and Other Structures. The International Residential Code represents the first time that wind, flood, and seismic loads are comprehensively addressed in a model for one- and two-family dwellings.

2/2000

In Disaster Assistance: Issues Related to the Development of FEMA's Insurance Requirements, the GAO concludes that FEMA had conscientiously sought to obtain and incorporate comments from stakeholders on its proposal to revise the Public Assistance program (see 11/1988, 7/1995, 1/1997, 3/1998, 11/1998, 1/1999, and 10/1999). In contrast, the GAO also finds that FEMA had not completed the analysis required for economically significant regulations.

2/2000

Seeking public comment and advice, FEMA publishes an Advance Notice of Proposed Rulemaking, which indicates FEMA's belief that its regulations covering Public Assistance insurance requirements are inadequate with respect to public buildings (see 11/1988, 7/1995, 1/1997, 3/1998, 11/1998, 1/1999, and 10/1999). The notice identifies three options; FEMA favors the option that would provide funds for the repair of public buildings, through federal disaster assistance, only if they are insured at the time of the disaster. States and local governments would have 36 months after the publication date of the final rule to purchase the required insurance.

4/2000

The Association of State Floodplain Managers publishes The Nation's Response to Flood Disasters: A Historical Account, which summarizes the forces and events that have affected floodplain management in the United States since the 1850s.

5/2000

The NFIP revises its fee schedule for processing certain types of requests for changes to NFIP maps and for processing requests for particular NFIP map and insurance products. The changes in the fee schedules are intended to further reduce the NFIP's expenses by recovering more fully the costs associated with processing conditional and final requests for map changes; retrieving, reproducing, and distributing technical and administrative data related to analyses and mapping; and producing, retrieving, and distributing map and insurance products.

6/2000

In collaboration with the H. John Heinz III Center for Science, Economics and the Environment, FEMA releases Evaluation of Erosion Hazards. The report responds to a congressional mandate included in Section 577 of the National Flood Insurance Reform Act of 1994. Noting that coastal erosion potentially jeopardizes nearly 87,000 homes, the report recommends that Congress should require FEMA to include the anticipated cost of erosion when setting flood insurance rates. The NFIP is not permitted to take into account expected losses from coastal erosion when establishing premiums for flood insurance.

6/2000

FEMA issues Call for Issues: Status Report, which summarizes the NFIP-related comments and suggestions of more than 170 stakeholders (see 9/1998).

6/2000

The NFIP issues rules that establish procedures for inspections to help verify that structures comply with a community's floodplain ordinances and to ensure that property owners pay flood insurance premiums commensurate with their flood risks. The procedures, to be used initially in a pilot study in Monroe County, Florida, will require owners of insured buildings to obtain an inspection from local floodplain officials as a condition of receiving insurance. Results of the pilot study will be evaluated before further implementation of the new procedures.

6/2000

FEMA sponsors a Floodplain Management Forum in Washington, DC, which gathers a group of experts on floodplain management together to discuss the future of floodplain management in the United States.

7/2000

PL 106-246 provides $50 million for the buyout and elevation of structures in states that received presidential disaster declarations in FY 1999 or 2000.

8/2000

At the request of the U.S. Senate's Committee on Banking, Housing, and Urban Affairs, the GAO initiates a study of the compliance of federally regulated lending institutions with the NFIP's mandatory-purchase provisions (see 12/1973, 1/1974, 8/1990, and 6/1999). The Flood Disaster Protection Act of 1973 prohibits such institutions from making, increasing, extending, or renewing any loan on a property without requiring flood insurance if that property is located in a SFHA within a community participating in the NFIP. As a result of the GAO study, FIA delays its own study on the subject.

8/2000

In response to the Consolidated Appropriations Act (PL 106-113) (see 11/1999), FEMA reports to Congress that there is no justification for reducing buyout assistance to property owners who fail to purchase and maintain flood insurance. In the report’s words, “Doing so will not result in any significant increase in the purchase of flood insurance, but will have the unintended consequence of effectively penalizing the low income populations most in need of federal assistance to move out of harm’s way….”

8/2000

In Opportunities to Enhance Compliance with Homeowner Flood Insurance Purchase Requirements, FEMA’s Inspector General examines compliance with the requirement for mandatory purchase of flood insurance by property owners with mortgages from federally regulated lending institutions. In its sample of structures, the Inspector General finds that 10 percent did not have flood insurance even though they met the requirements for mandatory purchase. The examination also notes that there is “no process to ensure that structures remapped into SFHAs are covered by or will be required to purchase a flood insurance policy.”

The report also observes that Group Flood Insurance Policies (see 3/1995 and 8/1996) appear to have lessened the costs of some disasters and appear to be cost-effective. In contrast, once the federal and state subsidies end for such policies, the low-income recipients of these subsidies rarely continue their coverage, although they are required to do so under the terms of their receipt of previously subsidized coverage.

9/2000

In an Audit of FEMA’s Cost Estimates for Implementing the Flood Map Modernization Plan, FEMA’s Inspector General concludes that the agency’s methodology for estimating the plan’s costs are generally sound but that FEMA “has not made significant progress in implementing the plan’s primary objectives” due to a lack of funds and the accuracy of the estimated costs of implementation should be improved.

9/2000

FEMA initiates the first comprehensive evaluation of the NFIP. A consulting firm is hired to design the evaluation and to assess the feasibility of evaluating questions in six areas of inquiry.

10/2000

FIA issues final regulations in the Federal Register that render the standard flood insurance policy in plain English and restructures its format to resemble a homeowner’s policy. In addition, use of FEMA’s new elevation certificate becomes mandatory.

10/2000

FEMA summarizes comments in the Federal Register from nearly 300 stakeholders who expressed their opinions about the agency’s proposed revisions to the Public Assistance program (see 11/1988, 7/1995, 1/1997, 3/1998, 11/1998, 1/1999, 10/1999, and 2/2000). Opponents claim that states and communities cannot afford to insure public buildings and that coverage would be difficult to obtain. FEMA notes that it will initiate a study on insurance coverage of publicly owned buildings and facilities.

10/2000

FEMA issues its Biennial Report to Congress on the Community Rating System. As of October 1, 926 communities are participating in CRS. Tulsa, Oklahoma continues to be the best rated community (see 10/1998), followed by Juno Beach and Sanibel, Florida; Kemah, Texas; and Pierce and Thurston Counties, Washington.

10/2000

The Disaster Mitigation and Cost Recovery Act (PL 106-390) amends the 1988 Stafford Act and provides authority to establish a program to provide technical and financial assistance to states and local governments to assist in the implementation of predisaster hazard-mitigation measures that are cost-effective and that are designed to reduce injuries, loss of life, and damage and destruction of property, including damage to critical services and facilities under the jurisdiction of the states or local governments.

The law also requires states to prepare a comprehensive state program for emergency and disaster mitigation prior to receiving funds from FEMA and directs the GAO to conduct a study to determine the current and future expected availability of disaster insurance for public infrastructure eligible for assistance under the Stafford Act.

The law further requires that FEMA discontinue its Individual and Family Grant Program as of May 2002 and replace it with a new program entitled “Financial Assistance to Address Other Needs” (see 2/1995).

11/2000

President William J. Clinton signs into law the Coastal Barrier Resources Reauthorization Act of 2000 (PL 106-514), which reauthorizes and amends the Coastal Barrier Resources Act (CBRA) (see 10/1982 and 11/1990). One provision of the Act allows for the voluntary addition of lands to the Coastal Barrier Resources System (CBRS) and could increase the amount of coastal barriers protected by CBRA. The Act also codifies a set of mapping criteria, which will help the public understand the technical basis behind delineating parts of the CBRS. Finally, the Act authorizes a pilot program to digitally map coastal areas and to improve the coordination of mapping efforts at the federal, state, and local levels.

12/2000

More than 200 communities are participating in Project Impact, FEMA’s predisaster mitigation program.

2000

FIA’s business process improvement initiative results in a “Blueprint for the Future” for the NFIP. Developed with the NFIP’s strategic partners, this blueprint will be the foundation for strategic and performance planning. When completed, Phase II will focus on FIA’s information technology requirements and capabilities. Strategies for information technology, which lead to optimum future operations, will be developed and assessed.

1/2001

In Compliance with Public Assistance Program’s Insurance Purchase Requirements, FEMA’s Inspector General notes that neither FEMA nor the states consistently maintain sufficient information to support their decisions on applicants’ insurance status (see 11/1988, 7/1995, 1/1997, 3/1998, 11/1998, 1/1999, 10/1999, 2/2000, and 10/2000). As a condition of receiving public assistance, recipients are required to protect insurable facilities by obtaining and maintaining insurance for the hazard that caused the damage. If the applicant does not maintain insurance, FEMA will not provide any assistance to that applicant in future disasters of the same type. In about one-third of cases examined, states, or communities did not maintain required insurance. In other instances, although proof of insurance was provided, some applicants for federal assistance purchased less insurance than required. FEMA generally agreed to implement the recommendations associated with the audit’s findings.

1/2001

Several environmental groups, including the Forest Guardians of Santa Fe, file suit in U.S. District Court in New Mexico alleging that the NFIP promotes inappropriate development in floodplains of the Rio Grande and San Juan Rivers and adversely affects the habitats of several endangered species.

2/2001

President George W. Bush submits to Congress his budget for 2002. This "Blueprint for New Beginnings" includes reforms to the National Flood Insurance Program aimed at saving $12 million dollars. The budget seeks to eliminate the availability of flood insurance coverage to several thousand "repetitive loss" properties and phase out the subsidization of premium rates for vacation homes, rental properties, and other nonprimary residences and businesses. The proposed budget would also eliminate funding for Project Impact (see 10/1997) because it "has not been proven effective."

2/2001

The U.S. House of Representatives' Committee on Financial Services indicates that its oversight plan for the 107th Congress includes attention to the implementation of the Community Development and Regulatory Improvement Act of 1994 (see 9/1994) and recent FEMA reports that address reductions in subsidies and repetitive losses (see also 2/1999).

2/2001

In Buyouts: Hurricane Floyd and Other Issues Related to FEMA's Hazard Mitigation Grant Program, FEMA's Inspector General notes that ambiguity in the legislation authorizing buyouts of properties damaged by Hurricane Floyd "caused significant delays in the commencement of the buyout process, contributed to much confusion and frustration over the funding requirement to execute such projects, and may have caused potential inequities in the type of structures targeted for buyout…" (see 11/1999 and 7/2000).

5/2001

The GAO provides testimony and submits a statement to the U.S. Senate's Committee on Appropriations, Subcommittee on Veterans, Housing, and Independent Agencies, on Emerging Opportunities to Better Measure Certain Results of the National Flood Insurance Program. The GAO finds that FEMA's performance goals do not assess the degree to which residents in flood-prone areas participate in the program. Noting that better data are needed on the number of structures in flood-prone areas, the GAO concludes that "Capturing data on the numbers of uninsured and insured structures in flood-prone areas can provide FEMA with another indication of how effectively the program is penetrating those areas most at risk of flooding, whether the financial consequences of floods in these areas are increasing or decreasing, and where marketing efforts can better be targeted."

6/2001

FEMA combines FIA and the Mitigation Directorate to form the Federal Insurance Administration and Mitigation Administration (FIMA).

6/2001

The NFIP eliminates its outstanding debt to the Department of the Treasury. This debt, which the NFIP had accumulated to pay for flood claims since the 1970s, had reached as much as $922 million in February 1999.

7/2001

In testimony before the U.S. House of Representatives' Committee on Financial Services, Subcommittee on Housing and Community Opportunity, FIMA's acting director notes that pre-FIRM, subsidized policies represent approximately 27 percent of all of its policies. Among all policies, approximately

15 percent of properties have accounted for 38 percent of all of the NFIP's losses.

8/2001

Robert F. Shea is appointed Acting Federal Insurance and Mitigation Administrator.

9/2001

The Office of Federal Housing Enterprise Oversight proposes (and subsequently adopts in December 2001) a regulation to codify the office's authority to oversee and enforce certain statutory requirements affecting the operations of government-sponsored enterprises regarding the NFIP.

10/2001

More than 4.37 million policies are in force, with a total coverage of approximately $594/5 billion. These policies are distributed among 19,713 communities, including 19,071 in the regular program and 642 in the emergency program (see 12/1969); 938 communities (with 66 percent of all policyholders) participate in the Community Rating System (see 10/1990).

12/2001

FEMA proposes to increase the amount of premium that policyholders must pay for flood insurance for pre-FIRM buildings in coastal areas subject to high-velocity waters, such as storm surges and wind-driven waves. If finalized, the increase will represent the fifth such increase in rates for such policyholders (see 3/1999). The purpose of the proposed increase is to reflect the insurance associated with their greater exposure to flood losses.

1/2002

In response to the Disaster Mitigation Act of 2000 (PL 106-390) (see 10/2000), FEMA proposes the consolidation of two disaster-relief programs, "Temporary Housing Assistance" and "Individual and Family Grant Program," into a single program called "Federal Assistance to Individuals and Households." In addition, FEMA proposes the elimination of Group Flood Insurance Policies (see 3/1995, 5/1996, 7/1999, 10/1999, and 8/2000), thus indicating its desire to "restore the responsibility for the flood insurance purchase requirement back to the individual or household receiving federal assistance."

1/2002

FEMA notifies officials in Monroe County, Florida, that its unincorporated areas may be placed on probationary status with the NFIP due to ongoing deficiencies in the local floodplain management program (see 6/2000).

3/2002

The NFIP amends its regulations to require that areas of Monroe County, Florida, that incorporate on or after January 1, 1999, and become eligible for the sale of flood insurance must participate in the inspection program as a condition of joining the NFIP (see 6/2000 and 1/2002).

3/2002

The NFIP initiates a three-year pilot project that will permit governmental risk-sharing pools to sell flood insurance to public entities under the NFIP's WYO effort. The NFIP limits participants in this pilot effort to a maximum of six such insurers that are able to provide flood insurance for their public buildings.

3/2002

Anthony Lowe is appointed Federal Insurance and Mitigation Administrator.

5/2002

FEMA's Inspector General publishes Extent that Mitigation Funds are Used to Address Repetitive Flood Loss and Other Related Issues. This report assesses the extent to which funds from the Hazard Mitigation Grant Program and the Flood Mitigation Assistance Program are used to acquire repetitive-loss properties. The report concludes that such funds could be used more effectively, especially with regard to the targeting of the most egregious repetitive-loss properties (see 11/1988, 9/1994, 9/1996, 9/1999, and 2/2001).

6/2002

The GAO completes Extent of Noncompliance with Purchase Requirements is Unknown. This report notes that flood insurance is required for properties located in flood-prone areas of participating communities for the life of mortgage loans made or held by federally regulated lending institutions or guaranteed by federal agencies. Mortgages purchased by Government Sponsored Enterprises (GSEs) are also included in this requirement as a result of the National Flood Insurance Reform Act of 1994 (see 9/1994). Despite the requirement, the GAO notes that no definitive analysis has been conducted that measures the extent to which property owners who are required to purchase insurance actually do so.

6/2002 continued

On the basis of examinations and compliance reviews, bank regulators and GSE officials believe that rates of noncompliance are low. In contrast, FEMA officials disagree with bank regulators and these officials, contending that rates of noncompliance are still significant. According to the GAO, these contrasting views are due to the fact that the regulators and FEMA use different measures to assess compliance. Nonetheless, the GAO concludes that analysis of the available data suggests that noncompliance could be low at loan origination.

6/2002

In Duplication of Benefits: National Flood Insurance Program and the Disaster Housing Program's Minimal Repair Grants, FEMA's Inspector General concludes that FEMA's internal controls are inadequate to detect and prevent duplication of benefits, which occurs when victims of floods receive benefits or assistance from more than one source for the same damaged property.

6/2002

The Task Force on The Natural and Beneficial Functions of the Floodplain, created by the National Flood Insurance Reform Act of 1994, concludes that the benefits provided by natural floodplains in flood loss reduction have been overlooked and that the protection and restoration of floodplains must be further integrated into government programs.

9/2002

With the issuance of an interim final rule in the Federal Register, FEMA consolidates the Temporary Housing Assistance and Individual and Family Grant Programs into a single program called Federal Assistance to Individuals and Households (IHP) (see 1/2002). FEMA indicates that states will have the option to be active partners in the administration of this new program, which provides a maximum of $25,000. Recipients of assistance from the IHP will be required to maintain flood insurance at least in the amount of the assistance, if they own the affected structure, for as long as the structure exists. The flood insurance requirement is reassigned to all subsequent owners of the flood-damaged address.

9/2002

In conjunction with the creation of the IHP (see previous entry), FEMA reverses its earlier proposal to eliminate Group Flood Insurance Policies (see 1/2002). FEMA increases the coverage to $25,000 from $14,800, reduces the term from 37 to 36 months, and retains a $200 deductible. The cost of the three-year policy increases to $600 from $200. The cost-sharing arrangements remain unchanged, with the states responsible for 25 percent of the cost and the federal government for 75 percent (funded as part of the IHP grant).

9/2002

In Invalid Preferred Risk Policies Based on Loss History, FEMA's Inspector General reviews policies with a repetitive loss history in Florida, Louisiana, Mississippi, Missouri, North Carolina, and Texas to determine which received a preferred risk rating. The audit finds that FEMA failed to invalidate 76 percent of the preferred risk policies (PRPs) included in the sample. To correct such problems, the Inspector General recommends FIMA review monitoring procedures to ensure WYO companies resolve rating errors in a timely manner.

10/2002

The NFIP pays the final $10 million installment on the $650 million it borrowed to pay claims arising from Tropical Storm Allison. The storm resulted in over 30,000 claims and approximately one billion dollars in claim payments.

10/2002

In Community Rating System: Effectiveness and Other Issues, FEMA's Inspector General determines the effectiveness of CRS as a tool to improve local policies and practices related to floodplain management. Overall, the report finds that CRS is a disciplined and well-defined program in terms of its guidelines, requirements, and rating processes and procedures. However, FIMA could enhance the effectiveness of CRS by: (1) performing Community Assistance Visits in all CRS communities, (2) marketing CRS to communities having greater exposure to the NFIP, (3) providing credit for increasing flood insurance coverage in a community, and (4) providing CRS coordinators with access to claims data.

2/2003

FEMA's Inspector General addresses the work done by three Flood Map Production Coordination Contractors (mapping contractors) in Audit of FEMA's Use and Management of Flood Mapping Contractors. The audit reveals that FEMA's management of mapping contracts needs strengthening especially in administration and support. According to the Inspector General, FEMA may have the ability to update more maps if it (1) reduces spending on processing Letters of Map Change, which accounted for 32 percent of contract spending over fiscal years 2000 and 2001, and (2) revises contracting strategies to increase competition and give contractors incentives to control costs.

3/2003

FEMA becomes part of the U.S. Department of Homeland Security and the Emergency Preparedness and Response Directorate.

5/2003

FEMA increases the maximum claim payout for Increased Cost of Compliance (ICC) coverage from $20,000 to $30,000 (see 6/1997).

8/2003

The NFIP has cash reserves of $580 million, which are available to pay future claims.

9/2003

FEMA recognizes Tulsa, Oklahoma, for outstanding achievements in reducing flood risks with a rating of Class 2 in CRS. Beginning in October 2003, property owners in the city will receive a 40 percent discount on their flood insurance premiums. Tulsa represents the first community in the nation to achieve a rating of Class 2.

9/2003

Hurricane Isabel, the only hurricane of the 2003 hurricane season to reach Category 5 status, makes landfall in North Carolina. Isabel results in extensive flooding in Baltimore and in other mid-Atlantic communities.

10/2003

FEMA offers states funds to upgrade their Map Modernization Implementation Plans (MMIP), developed in 2002, and develop the Flood Map Modernization State Business Plan. Using the Fiscal Year 2002 state plans as a starting point, states are asked to identify the projects to be completed each year, the role they play in managing the projects, and the support needed from FEMA. FEMA's Cooperating Technical Partner (CTP) initiative continues to be the funding mechanism for flood hazard mapping projects. A separate, distinct funding mechanism provides for the management activities identified in this plan.

03/2004

FEMA hosts the Mid-Atlantic Flood Insurance Summit to address concerns of Hurricane Isabel victims in settling flood insurance claims. Insurance companies, agents and adjustors, policyholders, insurance commissioners and Congressional staff meet in Falls Church , VA, to discuss solutions. As a result of the summit, FEMA begins to offer Isabel victims three ways to request flood insurance settlement review: by attending NFIP community outreach team visits, by using a toll-free number to initiate flood insurance settlement review, or by sending settlement review request form by mail. In April and May, community outreach teams visit hard-hit North Carolina, Virginia and Maryland communities to offer policyholders face-to-face discussions with claims specialists.

3/2004

The General Accounting Office (GAO) releases Actions to Address Repetitive Loss Properties on recent federal actions to target and reduce the number of repetitive loss properties, defined as properties for which policyholders have made two or more claims of $1,000 or more. About 1 percent of the 4.4 million properties currently insured by the program fit this definition. About 38 percent of all program claim costs have been the result of repetitive loss properties, at a cost of about $4.6 billion since 1978. The report concludes that FEMA’s strategy of targeting repetitive loss properties for mitigation and congressional proposals to raise premiums have the potential to reduce the number and vulnerability of repetitive loss properties.

3/2004

The General Accounting Office (GAO) releases the report Flood Map Modernization: Program Strategy Shows Promise, But Challenges Remain. The report finds several deficiencies in FEMA’s plan to implement updated maps of flood zones. In developing digital flood maps, FEMA plans to incorporate data that are of a level of specificity and accuracy commensurate with communities’ relative flood risk. FEMA has not yet established data standards that describe the appropriate level of detail, accuracy, and analysis required to develop digital maps based on risk level. Without such standards, FEMA cannot ensure that it uses the same level of data collection and analysis for all communities in the same risk category. FEMA has developed partnerships with states and local entities that have begun mapping activities and has a strategy on how to best work with these entities. However, the overall effectiveness of FEMA's future partnering efforts is uncertain because FEMA has not yet developed a clear strategy for partnering with communities with few resources and little or no experience in flood mapping. GAO recommends that FEMA should address differences among the communities for which flood maps are being developed.

3/2004

FEMA revises the Disaster Mitigation Act planning guidance and checklists for state and local hazard mitigation plans. Previously called the Interim Criteria for Mitigation (issued in July 2002), the guidance and checklists are been finalized as the Multi-Hazard Mitigation Planning Guidance. The new guidance includes references to specific language in the rule, descriptions of the relevant requirements, and sample plan text to illustrate distinctions between plan approaches that would and would not meet Disaster Mitigation Act 2000 requirements. In addition, this document provides references to planning tools that FEMA has made available to assist states, tribes, and localities in developing a comprehensive, multi-hazard approach to mitigation planning, and in preparing plans that will meet the DMA 2000 requirements.

4/2004

FEMA updates Increased Cost of Compliance—Guidance for State and Local Officials, a manual that helps officials understand the Increased Cost of Compliance (ICC) coverage provisions. The manual covers how the owners of buildings insured under the NFIP can benefit from ICC coverage, and how the coverage relates to community administration of the local floodplain management regulations and ordinances. The guidance highlights the new, increased maximum benefit level of $30,000 available to eligible policyholders (see 5/2003 and 6/1997).

5/2004

Connecticut's Governor Rowland signs into law House Bill 5045, An Act Concerning Floodplain Management and Hazard Mitigation, based in part on No Adverse Impact legislation. The new legislation requires municipalities to revise their current floodplain zoning regulations or ordinances to include new standards for compensatory storage and equal conveyance of floodwater. The Connecticut Department of Environmental Protection will develop model regulation language. The legislation requires the state to incorporate a natural hazards element into the next revision of its plan of conservation and development and enables municipalities to use local capital improvement funds from the state to conduct floodplain management and hazard mitigation activities.

6/2004

David Maurstad is appointed Acting Director of the Mitigation Division and Federal Insurance Administrator, replacing Anthony Lowe. His areas of oversight include the NFIP, the National Earthquake Hazards Reduction Program, the National Dam Safety Program and the National Hurricane Program. Mr. Maurstad previously served as Regional Director of FEMA's Region VIII since October 2001.

6/2004

President George W. Bush signs into law the Bunning-Bereuter-Blumenauer Flood Insurance Reform Act of 2004 (H.R. 253). The Act includes reforms to address repetitive loss properties and a reauthorization of the NFIP until September 30, 2008. Additional funding mechanisms focus mitigation efforts on "severe" repetitive loss structures that result in a disproportionate amount of claims to the National Flood Insurance Fund. The goals of the Act are to help people who have experienced serious and repetitive flood damage to solve their problems with financial assistance from the NFIP, communities, and states; to end the abuses by those who misuse the program; and to improve consumer understanding and rights of NFIP policyholders.

7/2004

FEMA issues an interim final rule in the Federal Register to amend the Federal Insurance Administration, Financial Assistance/Subsidy Arrangement and related regulations regarding issues of federal jurisdiction and applicability of federal law for lawsuits involving Write-Your-Own (WYO) Companies and of reimbursement to WYO Companies for the cost of litigation. Additionally, FEMA amends procedures for companies seeking to become, and ceasing to be, WYO Companies.

8/2004 to 9/2004

Florida experiences Tropical Storm Bonnie and Hurricanes Charley, Frances, Ivan and Jeanne. Hurricane and tropical storm related disasters are also declared in Alabama, Delaware, Georgia, Louisiana, Mississippi, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia and West Virginia.

12/2004

NFIP paid losses for 2004 number 52,785, about 45 percent more than the number of 2003 paid losses. FEMA pays out $1.9 billion in claims for 2004, or about 2 ½ times the amount paid out in 2003. FEMA uses $225 million in NFIP borrowing authority to pay 2004 flood loss claims.

4/2005

The President signs H.R. 1134, a measure to overturn a 2004 IRS ruling that made disaster mitigation funds taxable as income.

4/2005

In testimony before the Subcommittee on Housing and Community Opportunity, Committee on Financial Services, US House of Representatives, GAO reports that many private company insurance agents, who are the main points of NFIP contact for policyholders, have varying levels of NFIP knowledge. GAO also reports that FEMA has not met the six-month timeframe given for complying with the mandates of the Flood Insurance Reform Act of 2004, which require FEMA to establish agent training standards, but that FEMA has drafted the policyholder informational materials required by the Act.

7/2005

The Subcommittee on Housing and Community Opportunity, Committee on Financial Services, US House of Representatives, holds hearing on a GAO report, titled Flood Map Modernization: FEMA's Implementation of a National Strategy. GAO reports it found that the flood map modernization program lacked performance measures that would measure adequately the effectiveness of the map modernization program in meeting FEMA's goals. GAO notes, however, that FEMA had set target percentages in its Multi-Year Flood Hazard Identification Plan in response to the recommendations.

7/2005

Dennis becomes the first major hurricane to strike the US in the 2005 hurricane season. It reaches Category 4 status earlier in the hurricane season than any Atlantic storm since 1957. It strikes the Florida Panhandle in the same area affected by Hurricane Ivan the previous year, causing an approximate $4 to $6 billion in damage.

9/2005

Complying with Section 207 of the Flood Insurance Reform Act of 2004, FEMA issues a notice in the Federal Register that establishes minimum training and education requirements for all insurance agents who sell Standard Flood Insurance Policies issued through the NFIP.

8/2005 to 9/2005

Hurricane Katrina strikes Louisiana and Mississippi, resulting in flood wall and levee failures that cause up to 80 percent of the city of New Orleans to flood, leaving homes in some city neighborhoods with flood water levels up to the eaves for several weeks. Hurricane Rita strikes the Gulf Coast along the western Louisiana and eastern Texas shores, and New Orleans experiences new levee breaches and additional flooding.

9/2005

Michael Brown, FEMA director since 2003, offers his resignation. R. David Paulison, the director of FEMA's preparedness division, becomes interim FEMA director.

9/2005

After Hurricane Katrina, R. David Paulison, Acting Under Secretary of Homeland Security for Emergency Preparedness and Response, announces FEMA will modify the NFIP claim settlement process to expedite the response to policy-holders in storm-stricken areas.

9/2005

In response to Hurricanes Katrina and Rita, the President signs H.R. 3669, “The National Flood Insurance Enhanced Borrowing Authority Act of 2005” to increase the NFIP’s borrowing authority from $1.5 billion to $3.5 billion. The CBO estimates that FEMA probably will not be able to repay the funds borrowed under H.R. 3669 within the “next 10 years” and that Katrina-related claims will “exceed the total resources that will be available to FEMA under H.R. 3669” and that “repayments of borrowed funds would not occur until after 2015.”

10/2005

FEMA publishes a “Summary of Coverage” and a “Claims Handbook” for flood insurance policyholders, as required by the Flood Insurance Reform Act of 2004. The handbook is made available on the Internet. WYO companies and the NFIP Direct program begin distributing materials to policyholders as required by the 2004 Act.

10/2005

GAO testifies before the Subcommittee on Housing and Community Opportunity, Committee on Financial Services, US House of Representatives on Oversight and Management of the National Flood Insurance Program. GAO reports that FEMA has not yet fully implemented some of the provisions of the Flood Insurance Reform Act of 2004.

10/2005

David Maurstad, Acting Director of the FEMA Mitigation Division and Federal Insurance Administrator, testifies before the US Senate Committee on Banking, Housing and Urban Affairs on “The Future of the National Flood Insurance Program.” Mr. Maurstad reports to the Committee that magnitude and severity of flood losses caused by Hurricanes Katrina and Rita are “unprecedented in the history of the NFIP.” He states that Katrina and Rita-related flood claims would “result in flood insurance claims that significantly exceed the highest number of claims filed from any single event in the NFIP's history, and well more than triple the total number of claims filed in 2004." He states that Katrina and Rita-related NFIP claims could exceed $22 billion and that the NFIP in its entire history has paid out only $15 billion total.

10/2005

The National Science Foundation, the American Society of Civil Engineers, and the state of Louisiana begin to investigate the New Orleans floodwall breaches that led to massive flooding of the city after Hurricane Katrina. Defense Secretary Donald Rumsfeld announces that the National Academies of Science and Engineering will begin a separate probe into the New Orleans floodwall and levee failures.

10/2005

Eight tropical storm systems have struck southeastern US coasts during the 2005 season: Arlene, Cindy, Dennis, Katrina, Ophelia, Rita, Tammy and Wilma. Four of the eight—Dennis (July), Katrina (August), Rita (September) and Wilma (October)—are very destructive storms, and one—Katrina—becomes perhaps the most costly natural disaster in US history. The 2005 hurricane season becomes the most active on record, surpassing all previous hurricane seasons in number of named storms.

10/2005

The Subcommittee on Water Resources and Environment, Committee on Transportation and Infrastructure, US House of Representatives, holds two hearings inquiring into the causes of the New Orleans levee failures, and about ways in which New Orleans and other US cities at risk can be protected.

11/2005

The 2005 Atlantic hurricane season officially ends with a record 29 storms. Twenty-six were named storms, including 5 storms relying on Greek letters for their names. NOTE: on 12/30/05, the 2005 season continued with a 27th named storm, Zeta.

11/2005

President Bush signs legislation authorizing the NFIP to borrow up to an additional $18.5 billion to settle flood insurance claims for the 2005 claims year. David Maurstad states that further borrowing authority will be needed. Long-term NFIP reforms are also being considered along with the increases in borrowing authority.

11/2005

FEMA begins to release "advisory BFEs" and recovery maps that reflect post-hurricane data on flood risks for Katrina-affected Gulf Coast areas, so rebuilding can proceed based upon current understandings of base flood elevations. Localities are encouraged to adopt the advisory BFEs into their local ordinances. FEMA plans to issued revised FIRMs in the next year or two that are expected to closely resemble today's advisory BFE maps.

11/2005

The causes of the New Orleans flooding and levee breaches are explored in a hearing before the full US Senate Committee on Environment and Public Works. The US Army Corps of Engineers and members of engineering teams that are investigating the levee failures testify.

11/2005

Proposals for flood insurance reform are considered by the US House Financial services Committee in H.R. 4320. A number of changes to the NFIP are being considered, including increasing flood insurance coverage caps on structures and contents, and increasing fines imposed on lenders who fail to enforce mandatory flood insurance purchase requirements.

12/2005

Although it officially ended on November 30, the 2005 hurricane season continues with another named tropical system, Zeta. Zeta brings the total number of 2005 tropical systems to 30, including 27 named storms.

01/2006

With Zeta still active, the Atlantic hurricane season extends into January for only the second time since records have been kept.

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April 10, 2020

**VIA: ELECTRONIC FILING**

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's Petition for Approval of Storm Protection Plan
Dkt. 20200067-EI

Dear Mr. Teitzman:

Attached for filing in the above docket is Tampa Electric Company's Petition for Approval of Storm Protection Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

Malcolm N. Means

MNM/bmp
Attachment

cc: J.R. Kelly (w/o attachment)
Mireille Fall-Fry (w/o attachment)
TECO Regulatory Department

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| Review of 2020-2029 Storm Protection | ) | DOCKET NO. 20200067-EI |
| Plan pursuant to Rule 25-6.030, F.A.C., | ) | |
| Tampa Electric Company | ) | FILED: April 10, 2020 |

**TAMPA ELECTRIC COMPANY'S PETITION FOR APPROVAL OF STORM PROTECTION PLAN**

Tampa Electric Company ("Tampa Electric" or "the company"), pursuant to Section 366.96, Florida Statutes and Rule 25-6.030, Florida Administrative Code, petitions for Commission approval of its 2020-2029 Transmission and Distribution Storm Protection Plan ("SPP"). In support of this petition, the company states:

## I. Preliminary Information

1. The Petitioner's name and address are:

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

2. Any pleading, motion, notice, order or other document required to be served upon Tampa Electric or filed by any party to this proceeding shall be served upon the following individuals:

James D. Beasley
jbeasley@ausley.com
J. Jeffry Wahlen
jwahlen@ausley.com
Malcolm N. Means
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Paula K. Brown
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Manager, Regulatory Coordination
Tampa Electric Company
Post Office Box 111
Tampa, FL 33601
(813) 228-1444
(813) 228-1770 (fax)

3. Tampa Electric is an investor-owned "public utility" subject to the Commission's jurisdiction pursuant to Chapter 366, Florida Statutes, and is a wholly owned subsidiary of Emera, Inc.

4. Tampa Electric serves almost 800,000 retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties, Florida.

5. This petition is filed consistent with Rule 28-106.201, F.A.C. The agency affected is the Florida Public Service Commission, located at 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399. This Petition represents an original proceeding and does not involve reversal or modification of an agency decision or any proposed agency action.

## II. Plan Filing Requirement and Review Criteria

6. Pursuant to Section 366.96(3) of the Florida Statutes, each public utility must file "a transmission and distribution storm protection plan that covers the immediate 10-year planning period." The plan must "explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." § 366.96(3), Fla. Stat.

7. The Commission will review Tampa Electric's SPP under the four criteria set out in Section 366.96(4) of the Florida Statutes, which are:

> (a) The extent to which the plan is expected to reduce restoration costs and outage times associated with extreme weather events and enhance reliability, including whether the plan prioritizes areas of lower reliability performance.
> (b) The extent to which storm protection of transmission and distribution infrastructure is feasible, reasonable, or practical in certain areas of the utility's service territory, including, but not limited to, flood zones and rural areas.
> (c) The estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan.

(d) The estimated annual rate impact resulting from implementation of the plan during the first 3 years addressed in the plan.

8. Pursuant to Section 366.96(5) of the Florida Statutes, the Commission "shall determine whether it is in the public interest to approve, approve with modification, or deny" approval of Tampa Electric's SPP.

9. Rule 25-6.030 of the Florida Administrative Code is the Commission Rule that implements Section 366.96(3) of the Florida Statutes. It sets out the required contents for a storm protection plan. *See* R. 25-6.030(3)(a)-(j), F.A.C.

**III. Statement on Disputed Issues of Material Fact**

10. In compliance with paragraph (2)(d) of Rule 28-106.201, F.A.C., Tampa Electric states that it is not aware of any disputed issues of material fact at this time, but acknowledges the possibility that the Office of Public Counsel and other parties could assert disputed issues of material fact during this proceeding.

**IV. Statement of Ultimate Facts Alleged and Providing the Basis for Relief**

11. Tampa Electric's SPP is the result of a rigorous and comprehensive analysis of potential storm protection activities, including their potential costs and benefits. The company's SPP is attached as Exhibit 1 to this Petition.

12. Tampa Electric's analysis resulted in the identification and development of eight storm protection programs ("Programs"), four of which are comprised of multiple storm protection projects ("Project"). The Company's SPP also includes the continuation of legacy storm hardening initiatives in place since 2006 and wood pole inspections.

13. As explained further in the attached SPP, and in the testimony of Gerry R. Chasse, Regan B. Haines, John H. Webster, A. Sloan Lewis, and Jason D. De Stigter filed

contemporaneously with this petition, these Programs and Projects are the most cost-effective method of achieving the goals of Section 366.96 of the Florida Statutes.

14. Tampa Electric's SPP contains the following Programs:

- Distribution Lateral Undergrounding
- Vegetation Management
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancement
- Infrastructure Inspections
- Legacy Storm Hardening Plan Initiatives

15. These Programs collectively constitute the Company's "systematic approach to achieving the objectives of reducing restoration costs and outage times associated with extreme weather and enhancing reliability" as required by Section 366.96(3) of the Florida Statutes. Each Program is designed to individually achieve one or more of these objectives. The Programs will also operate synergistically to further these objectives.

16. Tampa Electric's SPP also contains each of the plan elements required by Rule 25-6.030(3) of the Florida Administrative Code.

a. Section 3 of the SPP includes a description of how implementation of the plan "will strengthen electric utility infrastructure to withstand extreme weather conditions" through hardening, undergrounding, and vegetation management as required by Rule 25-6.030(3)(a).

b. Section 3 of the SPP includes a description of how it "will reduce restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability" as required by Rule 25-6.030(3)(b) in Section 3 of the Plan.

c. Section 1 of the SPP includes a description of the utility's service area with the detail required by Rule 25-6.030(3)(c).

d. Section 6 of the SPP include a "description of each proposed storm protection program" that includes the detailed information required by Rule 25-6.030(3)(d).

e. Section 6 of SPP and the SPP Appendices include, for the first year of the plan, a description of each Project including actual or estimated construction start and completion dates, a description of the affected facilities, and a cost estimate including capital and operating expenses as required by Rule 25-6.030(3)(e)1. Some of the Programs, however, do not contain Storm Protection Projects.

f. Section 6 of the SPP includes, for the second and third years of the plan, "project related information in sufficient detail…to allow the development of preliminary estimates of rate impacts…" as required by Rule 25-6.030(3)(e)2. Some of the Programs, however, do not contain Storm Protection Projects.

g. The description of the Vegetation Management Program in the SPP includes a description of proposed vegetation management activities including the detail required by Rule 25-6.030(3)(f).

h. Section 7 of the SPP includes an estimate of the annual jurisdictional revenue requirements for each year of the plan as required by Rule 25-6.030(3)(g).

i. Section 8 of the SPP includes an estimate of the rate impacts for each of the first three years of the Plan for the utility's typical residential, commercial, and industrial customers as required by Rule 25-6.030(3)(h).

j. Finally, Section 9 of the SPP includes a description of all implementation alternatives that could have mitigated the rate impact for each of the first three years of the plan as required by Rule 25-6.030(3)(i).

17. Gerry R. Chasse's testimony introduces Tampa Electric's 2020-2029 SPP and explains how the implementation of the SPP will strengthen the company's infrastructure to withstand extreme weather conditions. His testimony also provides an overview of the company's service area and describes the process that the company used to develop the Plan, as well as a description of how the Plan's implementing Programs were selected and prioritized.

18. Regan B. Haines' testimony presents the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder Hardening, Infrastructure Inspection and Legacy Storm Hardening Initiatives Programs in Tampa Electric's 2020-2029 SPP. His testimony provides a description and explanation of how each Program will ensure the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability are achieved.

19. John H. Webster's testimony presents the Vegetation Management and Transmission Access Storm Protection Programs in Tampa Electric's 2020-2029 SPP. His testimony provides a description and explanation of how each Program will ensure the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability are achieved.

20. A. Sloan Lewis' testimony demonstrates that the company's 2020-2029 Storm Protection Plan complies with Rule 25-6.030(g)-(h), Florida Administrative Code, *i.e.*, the Storm Protection Plan Rule, by providing an estimate of the annual jurisdictional revenue requirements for each year of the SPP. Her testimony also provides an estimate of rate impacts for each of the first three years of the SPP for the company's typical residential, commercial, and industrial customers.

21. Jason D. De Stigter's testimony summarizes the results and methodology used by 1898 & Co. to develop a Storm Resilience Model for Tampa Electric. The Storm Resilience Model calculated the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers, prioritized hardening projects with the highest resilience benefit per dollar invested into the system, and established an overall investment level that maximizes customers' benefit while not exceeding the company's technical execution constraints.

**V. Relief Requested**

22. Tampa Electric respectfully requests that the Commission find that it is in the public interest to approve the Company's SPP without modification.

WHEREFORE, Tampa Electric Company respectfully urges the Commission to find that it is in the public interest to approve the Company's 2020-2029 Transmission and Distribution Storm Protection Plan without modification.

DATED this 10th day of April 2020

Respectfully submitted,

Malcolm N. Means

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

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# Tampa Electric's 2020–2029 Storm Protection Plan

Filed: April 10, 2020

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# Tampa Electric's
# 2020-2029 Storm Protection Plan Summary

Tampa Electric's 2020-2029 Storm Protection Plan describes the company's comprehensive approach to protect and strengthen its electric utility infrastructure to withstand extreme weather conditions as well as to reduce restoration costs and outage times in a prudent, practical and cost-effective manner. Protecting and strengthening Tampa Electric's transmission and distribution electric utility infrastructure against extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.

Tampa Electric's 2020-2029 Storm Protection Plan will be its first ten-year protection plan filed in response to Rule 25-6.030, Storm Protection Plan. That Rule, which became effective on February 18, 2020, requires utilities to file storm protection plans. Tampa Electric has developed this Plan to comply with the Rule. This Plan contains a description of the company's Storm Protection Programs, the specific supporting Projects to these Programs and required detail as prescribed by Rule 25-6.030. This Plan also incorporates the continuation of legacy Storm Hardening Plan Initiatives that have been in place since 2006 and wood pole inspections.

# Table of Contents

## 1 Tampa Electric's Service Area:

Tampa Electric's Service Area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties as shown in the figure below. The company's service area is divided into seven "service areas" for operational and administrative purposes. Tampa Electric provides service to 794,953 retail electric customers as of January 1, 2020.


Tampa Electric's transmission system consists of nearly 1,350 circuit miles of overhead facilities, including 25,416 transmission poles and structures. The company's transmission system also includes approximately nine circuit miles of underground facilities. The company's distribution system consists of approximately 6,250 circuit miles of overhead facilities and 414,000 poles. The company currently has approximately 5,550 circuit miles of underground distribution facilities. The company currently has 216 substations. Tampa Electric also has approximately 322,000 authorized joint user attachments on the company's transmission and distribution poles.

Tampa Electric developed the proposed 2020-2029 Storm Protection Plan and its supporting Programs and initiatives by examining the entire company's service area for the most cost-effective enhancement opportunities. Tampa Electric did not exclude any area of the company's existing transmission and distribution facilities for consideration for enhancement due to feasibility, reasonableness or practicality concerns.

## 2 References:

The following resources are referenced in this Plan:

a) 2017 National Electrical Safety Code
b) National Hurricane Center Database
c) Florida State Building Code
d) Hillsborough County Wind Maps
e) Tampa Electric’s prior Storm Implementation Plans
f) Tampa Electric’s Distribution Engineering Technical Manual
g) Tampa Electric’s Standard Electrical Service Requirements
h) Tampa Electric’s General Rules and Specifications-Overhead
i) Tampa Electric’s General Rules and Specifications-Underground
j) Tampa Electric’s Approved Materials Catalog
k) Hillsborough County Flood Hazard Maps

# 3 Storm Protection Plan Overview

Tampa Electric's Storm Protection Plan ("Plan" or "SPP") sets out a systematic and comprehensive approach to storm protection focused on those Programs and Projects that provide the highest level of reliability and resiliency benefits for the lowest relative cost. The company believes that these activities will achieve the Florida Legislature's goals of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability" in a cost-efficient manner.

In 2006 and 2007, the Florida Public Service Commission ("FPSC" or "Commission") issued two orders related to storm hardening and enacted Rule 25-6.0342, Florida Administrative Code ("F.A.C."), which requires utilities to prepare and submit a "Storm Hardening Plan" every three years. Through these actions, the Commission directed utilities to complete specific hardening activities, such as equipment inspections, post-storm data collection, and vegetation management cycles. In the years since, Tampa Electric Company has consistently performed these required activities and delivered significant storm resiliency benefits to customers.

In 2019, the Florida Legislature enacted a new law requiring utilities to prepare a "transmission and distribution storm protection plan." § 366.96(3), Fla. Stat. The statute requires utilities to develop a "transmission and distribution storm protection plan" setting out a "systematic approach" to reducing outage times and restoration costs associated with extreme weather and enhancing reliability. § 366.96(3), Fla. Stat. The Florida Legislature clearly intended that utilities should examine all options for achieving those goals, even those that go beyond the Commission's existing list of required Storm Hardening Plan activities.

In response to the new requirement to develop a comprehensive

SPP, Tampa Electric evaluated its existing Storm Hardening Plan activities and searched for potential additions and improvements. The company began by consulting its internal subject-matter experts to identify major causes of storm-related outages and major barriers to restoration following storms. The company then engaged three outside consultants to help it evaluate potential solutions and to assist with estimation of costs and benefits for those solutions.

First, Tampa Electric engaged Accenture, LLP (“Accenture”) to evaluate its existing vegetation management (“VM”) activities and determine what types of incremental vegetation trimming would reduce storm-related outage times and restoration costs. Tampa Electric’s Line Clearance Department and Accenture developed and finalized the SPP spending plan described in the VM section. Spending levels were evaluated for each of the initiatives, using multiple activities, and ultimately resulted in the proposed list of VM initiatives and spending levels. A complete copy of Tampa Electric’s Vegetation Management Storm Protection Program Analytic Support Report is included as Appendix “G”.

Second, Tampa Electric engaged 1898 & Co. to perform Project prioritization and benefits calculations for several of the company’s proposed Storm Protection Programs, including:

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

Tampa Electric and 1898 & Co. used a resilience-based planning approach to identify hardening Projects and prioritize investment in the transmission and distribution (T&D) system using 1898 & Co’s Storm Resilience Model. The Storm Resilience

Model consistently models the benefits of all potential hardening Projects for an accurate comparison across the system. The resilience-based planning approach calculates the benefits of storm hardening Projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, Project, and Program level. The results of the Storm Resilience Model are:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as Customer Minutes of Interruption(“CMI”)

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefits. A detailed overview of the Storm Resilience Model used to calculate the Project benefit and prioritize Projects is included in Tampa Electric’s Storm Protection Plan Resilience Benefits Report in Appendix “F”.

The storms database includes the future ‘universe’ of potential storm events to impact the company’s service area. 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. Each storm scenario was 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”) was based on the vegetation density around each conductor asset, the age and condition of the asset base, and the wind zone in which the asset is located. The Storm Impact Model also estimated the restoration costs and CMI for each of the Projects. Finally, the Storm Impact Model calculated the benefit in decreased restoration costs and CMI if that Project is hardened per the company’s hardening standards. The CMI benefit was monetized using the DOE’s Interruption Cost Estimator (“ICE”) for Project prioritization purposes.

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 employed stochastic modeling, or Monte Carlo Simulation, to randomly trigger the types of storm events to impact Tampa Electric's service area over the next 50 years. The probability of each storm scenario was 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 were evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

The Budget Optimization and Project Scheduling model prioritized the Projects based on the highest resilience benefit cost ratio. The model prioritized each Project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the Project cost. This was done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporated Tampa Electric's technical and operational (transmission outages) in scheduling the Projects.

This 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 receive the largest return on investment.

Early iterations of the modeling tool allowed the company to understand the Storm Protection Programs and the benefits that could be expected. In addition, Tampa Electric personnel factored the legacy Program Storm Hardening Plan Initiatives into these evaluations. Also, real-world considerations were included that examined practical realities of multi-year implementation, such as growing and sustaining an external workforce, scheduled outages, coordination of efforts and the ability to execute timely. Together, these aspects were used alongside the modeling tool to develop the final set of Programs, Program funding and ultimately individual Project selection. A complete copy of Tampa Electric's Storm Protection Plan Resilience Benefits Report is included as Appendix "F".

Third, Tampa Electric engaged Power Engineers, Incorporated, to perform an automation analysis for the (22) prioritized distribution circuits for the 2020-2022 Overhead Feeder Hardening Program. The analysis determined the number and placement of reclosers, conductor upgrades, substation transformer capacity increases, relay upgrades and in some instances circuit extensions, to meet the company's criteria to reduce customer exposure, impact and count for unplanned outages. These proposed system enhancements were also used as input to the broader 1898 & Co. analysis described below.

Finally, the company used the analyses provided by these consultants as a basis for establishing the spending levels in the proposed 2020-2029 SPP. This information was used in conjunction with technical and operational constraints to select Storm Protection Programs, Program funding levels and Project selection and prioritization. The company's 2020-2029 SPP is thus comprised of both the company's legacy Storm Hardening Plan activities, as well as those incremental activities that emerged from this rigorous analysis process to fully meet the goals, objectives and requirements of the Florida Legislature and the Commission.

# 4 Experience with Major Storm Events

Tampa Electric has significant experience preparing for, responding to, performing restoration and assisting other utilities in recovery from major storm events. The company's response to major storms that have impacted Tampa Electric's service area and the mutual assistance trips to assist other utilities have given Tampa Electric's restoration crews opportunities to gain valuable restoration knowledge and experience in restoring service after a major storm event. This knowledge includes the importance of conducting a damage assessment immediately after the storm has passed and providing customers with an accurate Estimated Time of Restoration ("ETR"). In addition to this experience, Hurricanes Matthew (2016), Hermine (2016), Harvey (2017), Irma (2017), Maria (2017) and Michael (2018) further exposed how vulnerable coastal regions are to the significant damaging effects of storm surge and the significant effort required to restore a system that has been impacted by coastal flooding. These experiences and industry best practices were discussed, analyzed and used to improve Tampa Electric's storm response plan.

Table 1 below provides the details of named storms affecting Tampa Electric's service area since 1960. The data is from the National Hurricane Center database.

**Table 1: Named Storms Affecting Tampa Electric Service Area since 1960**

| Year | Storm Name | Size [1] | Wind Speed [2] |
|---|---|---|---|
| 1960 | Donna | Cat 3 | 115 |
| 1995 | Erin | TS | 57 |
| 2004 | Charley | Cat 2 | 86 |
| 2004 | Francis | Cat 1 | 63 |
| 2004 | Jeanne | Cat 1 | 63 |
| 2005 | Dennis | TS | 43 |

| | | | |
|---|---|---|---|
| 2005 | Wilma | TS | 44 |
| 2006 | Alberto | TS | 45 |
| 2007 | Barry | TS | 31 |
| 2012 | Debby | TS | 53 |
| 2012 | Isaac | TS | 36 |
| 2013 | Andrea | TS | 47 |
| 2015 | Erika | TS | <39 |
| 2016 | Colin | TS | <39 |
| 2016 | Hermine | Cat 1 | 37 |
| 2016 | Matthew | TS | 20 |
| 2017 | Emily | TS | <39 |
| 2017 | Irma | Cat 1 | 90 |
| 2018 | Alberto | TS | 29 |
| 2019 | Nestor | TS | 26 |

Note 1: Maximum category when the storm passed through the Tampa Electric service area.

Note 2: Maximum sustained surface wind speed measured in miles per hour (“mph”) when the storm passed through the Tampa Electric service area.

# 5 Construction Standards, Policies, Practices and Procedures

Tampa Electric’s existing construction standards, policies, practices and procedures were developed over time to promote the ability of the company to provide safe and reliable electric service at reasonable rates. The company has included these standards, policies, practices and procedures in each of the three-year Storm Hardening Plans filed with and approved by the FPSC and is including these in this Plan document as important background and context for the Program elements of its Storm Protection Plan. The company will continue to evaluate and enhance its standards, policies, practices and procedures to incorporate new storm hardening and resiliency techniques.

## 5.1 National Electrical Safety Code Compliance

Tampa Electric’s construction standards and policies meet or exceed all minimum National Electric Safety Code (“NESC”) Rule requirements.

## 5.2 Wind Loading Standards

NESC Rule 250, which addresses pole loading requirements in the United States, is divided into three loading districts; Heavy, Medium and Light (see Figure 2 below). Tampa Electric’s service area is in the Light loading district, which assumes no ice buildup and a wind pressure rating of nine pounds per square foot. The nine-pound wind corresponds to wind speeds of approximately 60 mph. The Light loading district wind speed corresponds to a wind pressure of more than twice that in the Heavy or Medium districts due to the strong (non-linear) dependence of the wind force on wind speed (i.e., the wind pressure is proportional to the square of the wind speed). Another part of the NESC Rule 250 requires safety loading factors to be applied to the calculated wind forces to provide a conservative margin of safety when selecting appropriate pole sizes. A safety loading factor of 2.06:1 is applied to Grade C construction and 3.85:1 is applied to Grade B construction. The effective wind speed of Grade B new construction is approximately 116 mph. According to the NESC, Grade B wind loading criteria must be applied when constructing facilities less than 60 feet in height when crossing railroads, bridges and highways.

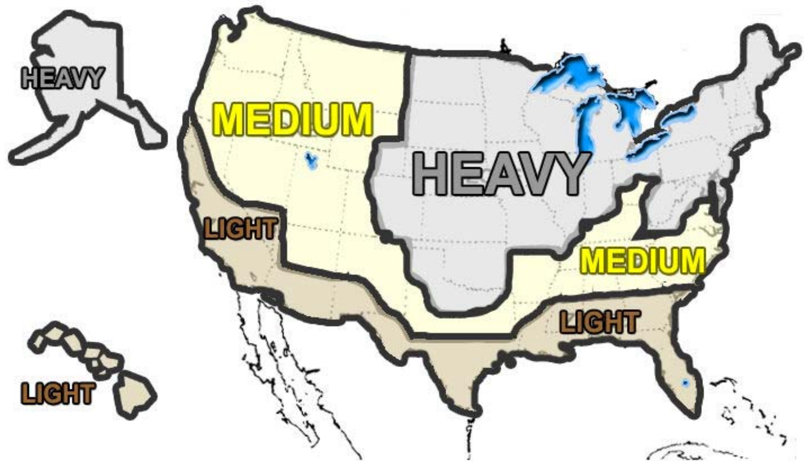


Figure 2: NESC General loading map of United States with respect to loading of overhead lines.

### 5.2.1 Extreme Wind Loading Criteria

The NESC also specifies an extreme wind pole loading criterion for all facilities constructed that are 60 feet in height or greater. The NESC provides a wind loading map that indicates the wind speed criteria for each area of the country. These same criteria and regional boundaries, developed by the American Society of Civil Engineers ("ASCE"), are used by the state of Florida and Hillsborough County for building code requirements. Tampa Electric's service territory is divided into two wind regions (see Figure 3 below). The western half is in the 120-mph zone and the eastern half is in the 110-mph zone.

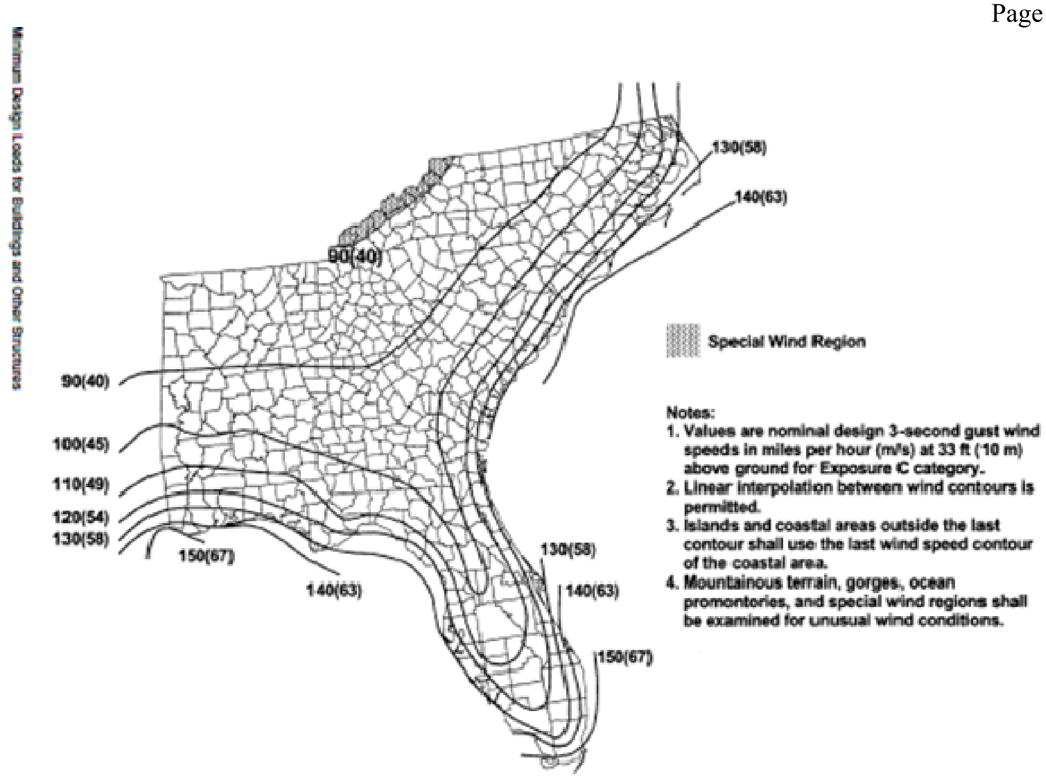


Figure 3: ASCE 74-10 Eastern Gulf of Mexico and Southeastern U.S. Hurricane Coastline

## 5.3 Distribution

This section of the Plan builds upon the design philosophy discussed above and provides an overview of the design criteria, construction standards and practices applicable to all new distribution facilities. This section also presents a broad discussion of the distribution materials and structure types the company uses.

Tampa Electric has developed and maintains a Distribution Engineering Technical Manual (“DETM”) which provides corporate and field personnel the policies, procedures and technical data related to the design of distribution facilities owned and operated by the company. Information contained in this manual along with the Standard Electrical Service Requirements (“SERS”), General Rules and Specification – Overhead (“GR&S-

OH”), General Rules and Specification – Underground (“GR&S-UG”) and the Approved Material Catalog (“AMC”) provide guidelines for designing, constructing and maintaining Tampa Electric’s distribution system.

### 5.3.1 Design Philosophy

The basis of Tampa Electric’s construction standards, policies, practices and procedures has been the NESC Grade B-Light since the 1980’s. All new overhead main feeder lines will be constructed to meet the NESC Extreme Wind loading criteria for our area. All new lateral lines will be constructed underground if doing so will reduce storm restoration costs and outage times. From this foundation, it supports the company’s philosophy of providing safe, reliable and cost-effective service to its customers.

### 5.3.2 Overhead System

#### 5.3.2.1 Voltage

Tampa Electric’s primary distribution system operates at a uniform 13.2 kilovolts (“kV”) at three-phase. Secondary voltage is provided in conjunction with the primary distribution system.

#### 5.3.2.2 Clearances

Primary voltage conductors are in the power space on the pole that is the upper most portion of the pole as defined by the NESC. Secondary and service conductors along with the neutral are located approximately six feet lower than the primary conductors. Joint use attachers are in the communication space on the pole which is at a minimum 40 inches below the neutral cable or Tampa Electric’s communication cable.

#### 5.3.2.3 Pole Loading

The company’s design and construction standard for all new construction, major planned work, expansions, rebuilds and relocations on the overhead distribution system will follow the

NESC construction Grade B criteria with the NESC Extreme Wind loading criteria applied to all Feeder main lines. As described above, the safety factors considered in the NESC construction Grade B criteria provide for a system that is 87 percent stronger than the NESC construction Grade C criteria which results in a more robust design. The company's experience has shown that this design provides safe, reliable and cost-effective service. This standard exceeds the minimum requirement of the NESC, which requires distribution poles to be designed to construction Grade C. While the NESC requirements related to extreme wind conditions apply to only structures over 60 feet in height and rarely apply to distribution structures, they will be used as a new design and construction standard for all new feeder construction and priority feeder hardening.

**5.3.2.4 Materials**

There are several types of poles that are used for distribution structures. Tampa Electric's distribution system uses wood, concrete, steel, ductile iron and fiberglass poles. The standard for all new distribution construction is Chromated Copper Arsenate ("CCA") treated wood poles as these CCA poles meet the strength requirements for most of the company's distribution line construction, have excellent life expectancy in Tampa Electric's service area (30+ years), are readily available, and cost effective.

The company's standard conductor for circuit feeders is 336 kcmil Aluminum Conductor, Steel Reinforced ("ACSR") with a 2/0 All Aluminum Alloy Conductor ("AAAC") neutral. Conductor sizes used for distribution laterals (overhead takeoffs from feeders) may either be #2, 2/0 or 4/0 AAAC with some older existing facilities containing #6 copper conductor.

#### 5.3.2.5 Construction Types

Proper configuration selection is important for safety, maintenance and economics. The company typically maintains the existing line configuration for multi-phase line extensions. Customer requests for alternative distribution pole and construction types will be considered and if agreed upon, the customer(s) requesting would incur the incremental expense from standard service.

Triangular line configuration using fiberglass brackets is the preferred construction standard. It is the most economical to install and is particularly suited to situations involving restrictive Rights-of-Way ("ROW"), easements and clearances. Because of its narrow profile, it is also preferred for locations with numerous trees. Other construction types that may be used include vertical, modified vertical and wood, or fiberglass cross arms.

#### 5.3.2.6 Pole Loading Compliance

Tampa Electric uses "PoleForeman," a pole loading software program to assure that Tampa Electric is following all NESC loading requirements and company construction standards. The program uses the company's construction standards with templates to model each pole and assist company distribution design technicians and distribution design engineers. The technician or engineer inputs the appropriate template, conductor, pole size and class, which the program uses to determine all loads on the pole. The program applies the loads to the structure and calculates the resulting stresses as a percent utilization of the pole.

### 5.3.3 Underground Facilities

#### 5.3.3.1 Standard Design

Tampa Electric's standard underground distribution system consists of normally looped circuits operating at 13.2kV three-phase or 7.6kV single-phase primary voltages. The standard cable is 15kV strand-filled jacketed tree-retardant cross-linked polyethylene insulated aluminum cable with a copper concentric neutral. Tampa Electric's standard is to place all underground distribution cables in a conduit system buried at depths of 24 to 36 inches from the ground surface to the top of the conduit.

#### 5.3.3.2 Network Service

Tampa Electric has several types of underground services with associated facilities. One is standard underground service that is used in residential subdivisions and commercial areas, which are described above. Another is network service, which provides a higher level of reliability and operating flexibility.

Tampa Electric employs two types of network service. The first type is an integrated secondary grid network that serves the high-density load area in downtown Tampa. The second type is spot network systems that also serves certain high-density loads in the downtown Tampa network area.

The network systems provide redundant circuit feeds from a two-transformer substation and thus are designed to maintain service during a first contingency outage. The network systems are also designed to resist water intrusion and the equipment is in vaults, some of which are below-grade. However, the customer-owned electrical panels are not necessarily waterproof and will likely be severely impacted by saltwater intrusion. This will possibly delay power restoration to network customers in the event of a major storm with storm surge into the network areas.

### 5.3.4 Construction Standards in Coastal Areas

Tampa Electric's service area is partially bounded by Tampa Bay and has approximately 60 square miles of land in the Flood Zone 1 designated area as defined in Hillsborough County's Hazard Flood Maps and approximately 2.5 square miles of land in the

Oldsmar area in the Flood Zone 1 designated area as defined in Pinellas County's Hazard Flood Maps. There is increased risk of storm surge, flooding and saltwater contamination along these coastal areas. Since 2008, the company's standard is that new underground distribution facilities (padmounted transformers, switchgear and load break cabinets) shall be of stainless steel or aluminum construction and bolted to a concrete pad. Upgrading the material from mild steel to stainless steel or aluminum makes it more durable and typically extends equipment life after saltwater contamination. While using stainless steel or aluminum has significant benefits to storm hardening, the equipment is not waterproof and may require cleaning prior to re-energizing after a flooding event. In addition, Tampa Electric has begun using submersible switchgear for customers in locations prone to flooding or where the switchgear can be subjected to harsh conditions. Since 2004, all primary switchgear has been specified using 100 percent stainless steel enclosures, and since 2008 all padmounted transformers have been specified using 100 percent stainless steel enclosures to reduce the corrosive effects from salt spray, effluent irrigation spray and to help harden the equipment against the corrosive effects of a saltwater storm surge.

In 2015, Tampa Electric began using submersible padmount switchgear to harden the underground system in certain applications. This switchgear is designed to withstand intrusion from water, including salt-water, while remaining in service. This gear will be specifically used for those critical customers in areas where storm surge is expected to have a significant impact or those low-lying areas where the environment has caused non-submersible switchgear to fail.

**5.3.5 Location of Facilities**

Tampa Electric's policy as stated in the DETM is to ensure that the route for new lines is located within the Public ROW or an electric utility easement. New residential lines shall be front lot construction and truck accessible. Commercial lines may be rear lot construction, but they must be truck accessible. This approach facilitates efficient access during installation and maintenance of the facilities. Prior to 1970 when this policy was instituted, some distribution facilities were constructed in rear lot easements. Communities or homeowner associations occasionally make inquiries regarding the relocation of overhead facilities from rear lot locations to the front of customer's properties. Tampa Electric evaluates each inquiry on a case-by-case basis for feasibility, practicality and cost-effectiveness.

#### 5.3.6 Critical Infrastructure

Tampa Electric, in conjunction with local government emergency management, has identified the company's critical facilities and associated circuits feeding loads which are deemed necessary for business continuity and continuity of government. As such, critical community facilities are identified based on being most critical to the overall health of the community, including public health, safety or the national or global economy. Such facilities include hospitals, emergency shelters, master pumping stations, wastewater plants, major communications facilities, flood control structures, electric and gas utilities, EOC, as well as main police and fire stations, and others. The circuits serving these facilities have the highest restoration priority level. Tampa Electric has hardened several circuits which feed some of the most critical customers on the company's system to extreme wind criteria.

### 5.4 Transmission

This section of the Plan provides an overview of design considerations and references when performing a transmission structure analysis for new and existing facilities. This section is a broad discussion of transmission structure types, foundation design and design criteria.

**5.4.1 Design Criteria**

There are two types of methodologies used to analyze pole strength. Tampa Electric uses the ultimate strength analysis for all wood and non-wood structures. However, it is acceptable and often recommended to use the working stress method for wood poles.

Tampa Electric designs and specifies all transmission facilities in accordance with the latest version of the NESC. All designs address NESC extreme wind and Grade B construction at a minimum. The extreme wind loads are applied to all attachments on the transmission structure regardless of attachment height.

Tampa Electric’s service area is largely within the 100 mph to 120 mph extreme wind contours referenced in the NESC. For design consistency, the 120-mph wind standard is applied on all 69kV structures throughout the service area. In addition, a 133-mph wind standard is applied to all 138kV and 230kV structures throughout Tampa Electric’s service area. The 133-mph wind standard exceeds the NESC requirements for extreme wind loading. This standard was adopted when Tampa Electric commissioned the first 230kV line in the company’s service area. Tampa Electric continues to support the 133-mph wind standard as the best practice for 138kV and 230kV line construction.

Since the inception of the NESC extreme wind standard, it has been applied to Tampa Electric transmission facilities. Tampa Electric historically has applied the 133-mph wind standard to 230kV facilities and in some cases an even higher wind speed has been applied when the company determined that the circuit would be very difficult to restore. An example of this higher wind standard is when the company replaced the transmission structures crossing the Alafia River. For these structures, a 150-mph wind standard was used.

### 5.4.2 Transmission Structures

#### 5.4.2.1 Voltage levels

Tampa Electric's transmission system consists of circuits operating at 230kV, 138kV and 69kV. These circuits consist of a minimum of three phase conductors and (usually) a static wire (ground). Additional facilities may exist or be incorporated in the design of a transmission structure, including additional transmission conductors, optical ground wire, communication conductors, distribution conductors and an assortment of wire attachments by joint users.

#### 5.4.2.2 Material types

Tampa Electric's transmission system consists of wood, concrete, aluminum, steel and composite supporting structures. Since 1991, Tampa Electric has used a standard that all new construction, line relocations and maintenance replacements will use pre-stressed spun concrete, steel or composite pole structures. Past practices included wood pole, aluminum and lattice steel structure design. Pre-stressed spun concrete, tubular steel and composite poles are now the preferred structure material types Tampa Electric installs when replacing or upgrading structures.

#### 5.4.2.3 Configuration Types

Tampa Electric uses multiple transmission structure configurations. Pre-stressed spun concrete poles and tubular steel poles are used in single or multiple pole configurations. The advent of pre-stressed spun concrete and tubular steel poles has permitted a more cost-effective, lower maintenance and higher strength option.

The configurations will vary widely when considering the many variables associated with transmission facilities. Some of these variables are:

- Number of circuits
- Conductor size
- Structure strength
- Span length
- Soil conditions
- ROW width
- Potential permitting requirements
- Utilization of adjacent land
- Environmental impacts
- Electric and magnetic field criteria
- Aesthetics
- Economics and cost–effectiveness
- Community input

Single pre-stressed spun concrete or tubular steel structure configurations have proven to be the most economical and maintainable choice given the work environment and constraints encountered while engineering and constructing transmission facilities. Prior to pre-stressed spun concrete and tubular steel technology, typical structure configurations commonly consisted of single wood pole or multiple wood pole structures, lattice aluminum H-frames and lattice steel towers.

**5.4.3 Foundations**

Direct embedment is the preferred foundation type used for pre-stressed spun concrete, tubular steel or composite structures. A direct embedded foundation typically has a specified depth and diameter. The direct embedded foundation also requires a segment of the superstructure to be embedded below ground, acting as part of the foundation, along with natural soil, crushed rock or concrete backfill.

When a structure location requires it, Tampa Electric uses an industry accepted program for foundation design. Soil borings are collected, or standard penetration tests are conducted to compile the appropriate soil data for foundation analysis.

**5.5 Substation**

Tampa Electric has developed and maintains a Substation Engineering Technical Manual ("SETM") which provides the company's personnel with the policies, procedures and technical date to the design of substation facilities owned and operated by the company. Information contained in the SETM along with the Standard Electrical Service Requirements ("SESR"), GR&S-OH, GR&S-UG and AMC, provide guidelines for designing, constructing and maintaining Tampa Electric's substation facilities.

Tampa Electric designs, constructs and maintains transmission and distribution substations and switchyards ranging from 13.2kV to 230kV. This includes performing siting studies, physical design, grading and drainage, foundation design, layout and design of control buildings, structure design and analysis, protection and control systems, and preparation of complete specifications for material, equipment and construction. The company currently has 216 substations.

**5.5.1 Design Philosophy**

**5.5.1.1 Wind Strength Requirements**

Tampa Electric designs the company's substations in accordance with the latest approved version of the NESC. Currently, all distribution substation structures are designed to withstand a wind load of 120 mph. All current design standards for 230kV generation facilities and 230kV transmission stations call for terminal line structures to withstand 133 mph wind loading along with the line tension of the transmission circuit.

The design standards summarized above meet the NESC loading criteria for extreme wind, Grade B construction. As previously stated, Tampa Electric’s service area is within the 100 mph to 120 mph extreme wind contours referenced in the NESC.

### 5.5.1.2 Equipment Elevations

The company carefully evaluates equipment elevations when building on existing sites or when selecting future sites in the Flood Zone 1 designated area. Information on past flooding in localized areas and potential future storm surge levels are evaluated. Most equipment is built on steel supports and is above expected flood levels. Some equipment such as transformers can be submerged up to the point of attached cabinets and controls. Therefore, the major focus is on the elevation and water resistance of the control cabinets and related equipment. The sites and/or equipment are elevated based on the overall site permitting that must be done with the governmental and environmental agencies while taking into consideration the surrounding area.

### 5.5.1.3 Protection

Animal protection covers are installed on all new 13kV bushings, lightning arrestors, switches and leads. This helps prevent outages caused by animals and will also reduce damage from debris that may get inside the substation during a major storm event. Tampa Electric uses circuit switchers instead of fuses or ground switches on new and upgraded transformer installations. This design will clear a fault faster which minimizes damage and greatly reduces restoration time.

### 5.5.1.4 Flood Zones

The company carefully evaluates flood zones when building on existing sites or when selecting future sites. The company will continue to review existing sites in the Flood Zone 1 designated area. The major focus will be on the elevation and water resistance of control cabinets and related equipment. Prudent modifications will be made. Consideration will be given to whether there will be load to be served in the area of the substation immediately after a storm and if any load can be served from adjacent substations that are outside the flooded area.

#### 5.5.1.5 Other

When transformers are added to an existing substation or a transformer is upgraded, if needed, existing fences are removed, and new fences are installed to meet or exceed current NESC wind and height standards. At the same time, animal protection covers are installed on all 13kV bushings, lightning arrestors, switches and leads. This helps prevent damage from debris that gets inside the substation.

### 5.5.2 Construction Standards

Tampa Electric uses galvanized tubular steel structures in new distribution substations. The tallest structure is approximately 24 feet above grade, with most of the structures and equipment being below 17 feet. Distribution feeder circuits are designed to exit the substation via underground cables installed inside six-inch conduit.

In 230kV substations and 69kV switching stations, control buildings are used to house protection relays, communication equipment, Remote Terminal Unit (“RTU”) monitoring equipment and substation battery systems. Previous construction methods used concrete block construction with poured concrete columns and concrete roof panels, which are designed to withstand winds of 120 mph without any damage to the building or the equipment housed inside. Control buildings currently being installed are prefabricated metal buildings designed for 150 mph wind loading. Tampa Electric installs eight-foot tall perimeter chain link fences designed to 120 mph or walls designed to 125 mph. This provides additional protection from wind-blown debris. Tampa

Electric has determined that this fencing standard is most effective in blocking debris and exceeds county codes.

### 5.6 Deployment Strategy

Tampa Electric's 2020-2029 Storm Protection Plan's deployment strategy will reduce storm restoration costs and customer outage duration following major storm events and enhance system reliability through the continuation of several core components of the company's Storm Hardening Plans. The deployment strategy includes the continuation of legacy Storm Hardening Plan Initiatives and the implementation of new and expanded Storm Protection Plan Programs.

# 6 Storm Protection Plan Programs

Tampa Electric's proposed 2020-2029 SPP includes several newly developed incremental Storm Protection Programs, Projects and activities that resulted from the thorough and comprehensive analysis previously described. These new Programs, as well as the company's legacy Storm Hardening Plan activities, are described in this section. These Programs will achieve the goals, objectives and requirements of the Florida Legislature and the Commission.

## 6.1 Distribution Lateral Undergrounding

Tampa Electric's Distribution Lateral Undergrounding Program aims to strategically underground existing overhead lateral primary, lateral secondary and service lines. The expected benefits from this Program are:

- Reducing the number and severity of customer outages during extreme weather events;
- Reducing the amount of system damage during extreme weather;
- Reducing the material and manpower resources needed to respond to extreme weather events;
- Reducing the number of customer complaints from the reduction in outages during extreme weather events; and
- Reducing restoration costs following extreme weather events.

In addition to the many benefits that should be realized from distribution lateral undergrounding during extreme weather events, it will also provide additional blue-sky benefits such as:

- Reducing the number of momentary and prolonged unplanned outages;
- Reducing the number of customer complaints from outages; and
- Improving customer reliability and power quality.

Tampa Electric’s Distribution System is currently comprised of the following Key Metrics:

- Total Circuit Miles: 11,800
- Total Overhead Miles: 6,251 (53 percent)
- Total Underground Miles: 5,549 (47 percent)
- Total Overhead Lateral Miles: 4,471
- Total Overhead Feeder Miles: 1,780
- Total Underground Lateral Miles: 4,949
- Total Underground Feeder Miles: 600
- Customers served off Laterals: 88 percent
- Customers served off Feeders: 12 percent

Tampa Electric and its customers have been fortunate because the company’s service area has incurred only one direct hit from a large, strong, named storm in the last 15 years (Hurricane Irma in 2017). The table below reflects Tampa Electric’s distribution system “OH versus UG” outage comparison across “day-to-day”, Major Event Days, and Hurricane Irma.

**Tampa Electric's Distribution System**
**Overhead versus Underground**
**Outage Comparison (in Percent)**

| | Distribution System | Day-to-Day Outages | Major Event Day Outages | Irma Repair/Replace |
|---|---|---|---|---|
| **Overhead** | 53 | 81 | 91 | 99.60 |
| **Underground** | 47 | 19 | 9 | 0.40 |

These metrics show that the underground system proves to be much stronger and more resilient during extreme weather events. The Distribution Lateral Undergrounding Program is projected to receive the largest share of the SPP funding over the next ten years. This SPP Program is also expected to provide similar reliability improvements and restoration benefits (time and costs) during normal day-to-day operations and summer thunderstorm events.

As previously discussed, Tampa Electric used the 1898 & Co.

modeling tool to assist in the prioritization of individual Projects and to set the overall Program funding levels for the Distribution Lateral Undergrounding Program. Initial model runs provided the optimal 10-year SPP spending levels and demonstrated that this Program's undergrounding Projects provided high net benefits to customers in the form of reduced restoration costs and CMI. Tampa Electric relied on the model output to confirm appropriate funding levels in alignment with the need to attract and sustain external workforces capable of executing a large-scale Distribution Lateral Undergrounding Program for the duration of the 2020-2029 SPP. The company also relied on the model output to identify the 2020-2021 Projects, selecting Projects that would allow it to most rapidly grow the Program, execute at small scale initially and develop operationally sound, sustainable and efficient processes. The individual Projects, the prioritization of these Projects and the annual Program funding levels are supported by the model. For operational efficiencies, laterals on the same feeder circuit were grouped and scheduled together in the same time frame. Laterals were then selected based on their ease of execution (e.g. fewer joint use attachers, fewer rear lot spans, and no major road or railroad crossings) balanced against their customer benefits. Strategically and operationally, these Projects are intended to allow the company to most rapidly complete projects to learn, adapt and enhance its processes to ensure the Program is sustainable, efficient and cost-effective. The 2020 activity will largely consist of designing, permitting, obtaining easements and attempting to coordinate with joint users on the identified Projects in detail included in Appendix "A". While this currently reflects a construction quarter end date of "Q4 2020" for these Projects, the Projects can be completed only if all permitting and required easements are obtained. The company anticipates the permits and easements will be obtained, however if they cannot be, the company will begin the process by accelerating future planned Projects into

2020.

For the SPP years 2022 to 2029, the modeling tool grouped laterals by Feeder Circuit and prioritized them annually based on their net benefit to customers.

The table below shows the Distribution Lateral Undergrounding Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 24 | $8.0 |
| 2021 | 281 | $79.5 |
| 2022 | 316 | $108.1 |

The full detail of the supporting Distribution Lateral Undergrounding individual Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix "A".

### 6.2 Vegetation Management

Tampa Electric's Vegetation Management Program ("VMP") combines a continuation of its existing filed and approved distribution and transmission VMP activities with three additional strategic VM initiatives.

#### 6.2.1 Existing Vegetation Management Activities

Tampa Electric currently trims the company's distribution system on a four-year cycle. This approach was approved by the Commission in Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI, issued June 12, 2012. The four-year cycle is flexible enough to allow the company to change circuit prioritization utilizing the company's reliability-based methodology. Since 2007, Tampa Electric has partnered with a third-party consultant and used their proprietary vegetation management software application. The software analyzes multi-year circuit performance data, trim cycles, and corrective and restoration costs to generate a priority list for circuit trimming for the four-year distribution trimming cycle. The software optimizes circuit selection in terms of both reliability and cost-effectiveness.

The company also adheres to a comprehensive vegetation management strategy for its transmission system. The company operates three categories of transmission lines 230kV, 138kV, and 69kV. For the circuits with voltages above 200kV, the company complies with Federal Energy Regulatory Commission ("FERC") standard FAC-003-4. This standard imposes performance-based, risk-based, and competency-based requirements for vegetation management on these circuits. The company imposes a two-year vegetation management cycle for 138kV circuits, and a three-year cycle for 69kV circuits. The company's vegetation management strategy for its transmission system includes the maintenance of the transmission ROWs.

### 6.2.2 New VMP Initiatives

In addition to continuing its existing VMP plans, Tampa Electric partnered with Accenture to analyze various VMP strategies to further enhance the transmission and distribution facilities while reducing outage times and restoration costs due to extreme weather conditions. Accenture updated its existing vegetation management software to include the most recent outage, cost, and trim data, and to add functionality to estimate the value derived from activities that address only part of a circuit at a time. Tampa Electric and Accenture then analyzed and compared full and partial circuit vegetation management activities based on their expected cost and benefit during extreme weather events, as well as overall service reliability. Based on this analysis, Tampa Electric is proposing two additional distribution VM initiatives and one additional transmission VM initiative. The purpose of these additional VM initiatives is to enhance the company's current cycles, specifically for the purpose of system storm hardening. These additional VM initiatives are:

Initiative 1: Supplemental Distribution Circuit VM
Initiative 2: Mid-Cycle Distribution VM
Initiative 3: 69 kV VM Reclamation

#### 6.2.2.1 Initiative 1: Supplemental Distribution Circuit VM

Tampa Electric and Accenture evaluated the costs and benefits of enhancing the current four-year distribution VM cycle by trimming additional miles each year to reduce the proximity between vegetation and electrical facilities. The team determined the cost of supplemental trimming would be justified by significant benefits including: (1) decreases in storm restoration costs; (2) decreases in corrective maintenance costs and day-to-day outage restoration costs; (3) improvements in day-to-day reliability; and (4) a reduction in the cost of the baseline 4-year trim cycle. Accenture analyzed multiple annual mileage increment scenarios. The analysis showed that each incremental increase in trimming will yield the above-described benefits, but these benefits eventually hit a point of diminishing returns. Accenture ultimately recommended 700 miles of supplemental VM would provide the greatest benefits for the estimated cost.

Circuit prioritization and selection will be centered around storm resiliency and mitigating outage risk on those circuits most susceptible to storm damage. Accenture's VM software will generate annual circuit trim lists by emphasizing storm resiliency. The Supplemental Circuit VM initiative schedule by Tampa Electric's Service Area and year for the affected miles and customers is detailed below:

| Supplemental Vegetation Management Project Schedule by Service Area | | | | | | |
|---|---|---|---|---|---|---|
| | 2020 | | 2021 | | 2022 | |
| Service Area | Miles | Customers | Miles | Customers | Miles | Customers |
| Central | 77.9 | 21,357 | 159.1 | 29,226 | 113.5 | 20,418 |
| Dade City | 99.9 | 5,208 | 6.2 | 484 | 127.6 | 5,578 |
| Eastern | 99.8 | 18,598 | 153.3 | 12,341 | 72.9 | 8,794 |
| Plant City | 76.7 | 9,702 | 25.2 | 2,443 | 202.2 | 8,347 |
| South Hillsborough | 15.3 | 2,264 | 20.5 | 2,427 | 20.2 | 3,236 |
| Western | 15.7 | 3,926 | 82.8 | 13,024 | 112.4 | 20,376 |
| Winter Haven | 16.8 | 1,277 | 63.1 | 5,063 | 43.2 | 5,784 |
| Total | 402.3 | 62,332 | 510.2 | 65,008 | 692 | 72,533 |

The total Supplemental Circuit VM initiative costs are detailed below for the 2020-2029 SPP:

| Supplemental Vegetation Management Project Costs (in thousands) | |
|---|---|
| 2020 | $3,200 |
| 2021 | $5,200 |
| 2022 | $6,100 |
| 2023 | $7,100 |
| 2024 | $4,800 |
| 2025 | $5,300 |
| 2026 | $6,500 |
| 2027 | $5,900 |
| 2028 | $5,900 |
| 2029 | $5,900 |

#### 6.2.2.2 Initiative 2: Mid-Cycle Distribution VM

Tampa Electric’s experience with existing VM activities is that some trees cannot be effectively maintained within the four-year distribution VM cycle because of their rapid growth rate. For instance, the company estimates that up to twenty-five percent of trees grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. Additionally, some trees develop into a threat to distribution facilities due to an evident defect or hazard trees. The current four-year cycle has limited tree removal potential. Fall-in trees were determined to be a major damage factor in recent storms.

The Mid-Cycle VM initiative is inspection-based and designed to identify and selectively mitigate these trees. Tampa Electric and Accenture's analysis showed that this initiative will lead to reductions in both extreme weather outages and restoration costs as well as day-to-day outage costs. For the first three years of the Storm Protection Plan, the company will inspect feeders that have not been trimmed in the last two years and then prescribe additional VM work based on the inspection findings. After the first three years, the company plans to expand the initiative to include laterals. The Mid-Cycle VM initiative schedule by Tampa Electric's Service Area and year for the affected miles and customers is detailed below:

| Mid-Cycle Vegetation Management Project Schedule by Service Area | | | | | | |
|---|---|---|---|---|---|---|
| | 2020 | | 2021 | | 2022 | |
| Service Area | Miles | Customers | Miles | Customers | Miles | Customers |
| Central | 0 | 0 | 48.6 | 17,262 | 36 | 9,488 |
| Dade City | 0 | 0 | 2.8 | 1,293 | 5.1 | 904 |
| Eastern | 0 | 0 | 17.3 | 4,730 | 34.5 | 12,007 |
| Plant City | 0 | 0 | 18 | 8,234 | 12 | 7,191 |
| South Hillsborough | 0 | 0 | 51.7 | 16,233 | 23 | 13,900 |
| Western | 0 | 0 | 58.8 | 27,318 | 53.3 | 19,073 |
| Winter Haven | 0 | 0 | 45.9 | 20,663 | 32.1 | 14,565 |
| Total | 0 | 0 | 243.1 | 95,733 | 196 | 77,128 |

The total Mid-Cycle VM Project costs are detailed below. The 2020 costs are associated with the initial inspections.

| Mid-Cycle Vegetation Management Project Costs (in thousands) | |
|---|---|
| **2020** | $100 |
| **2021** | $1,200 |
| **2022** | $3,500 |
| **2023** | $4,000 |
| **2024** | $5,600 |
| **2025** | $6,000 |
| **2026** | $5,700 |
| **2027** | $6,200 |
| **2028** | $7,300 |
| **2029** | $6,300 |

#### 6.2.2.3 Initiative 3: 69kV VM Reclamation

The 69kV Reclamation Project is designed to “reclaim” specific areas of the company’s 69kV system that are particularly problematic due to vegetative conditions. These areas are difficult and expensive to maintain and frequently contain hazard trees. While the company’s robust trim cycles are effective against vegetation to conductor encroachments on 90 percent of the 69kV circuits, the remaining portion are in areas that are either low-lying or restricted by vegetation overgrowth. The focus of this Project is to clear the vegetation undergrowth and remove the hazard trees. The company plans to clear the vegetation within the boundaries of the easement or property but outside of the current 15-foot vegetation-to-conductor clearance specification. The extent of trimming will be driven by the rights set forth in the company’s property deeds and easements, so the company plans to research existing easements and deeds and survey where necessary. Affected customers and property owners will be kept abreast of work occurring in their area.

An additional benefit to the Project is improved access. One of the VM lessons learned from recent storm recovery efforts is that unobstructed access to transmission facilities is critical to minimizing restoration times. Clearing these vegetation-obstructed areas will reduce outage potential, allow for faster restoration times, and lower restoration costs due to the following:

- Improving vegetation to conductor clearances will reduce blow-in outages;
- Removing hazard trees will reduce fall-in outages;
- Removing vegetation overgrowth will allow the ground to dry faster, promoting deeper tree roots and improving accessibility, reducing the need for access matting;
- Outage locations can be identified much easier, up to 200 percent faster;
- Damage assessment can be completed more accurately;
- Safer work sites reduce the number of personnel and equipment needed to restore; and
- Normal line and vegetation inspection and maintenance costs will be reduced by the improved clearances and unobstructed access.

The time to restore transmission outages is dependent on several factors, such as voltage, switching, design, and other facility impacts, but the key factor to restoration is accessibility. Outages that occur in areas obstructed by vegetation, on average, take up to 75 percent longer to restore. Tampa Electric has identified areas along the 69kV system where these vegetative conflicts and obstructions exist and mapped them to determine Project scope, cost, and schedule. The entire 69kV Vegetation Reclamation Initiative is a short-term initiative planned for four years beginning in 2020 and concluding in 2023. The Project scope and cost detail for the 69kV Vegetation Reclamation Initiative is listed below.

| Project Scope | | | Total Project Costs (in thousands) |
|---|---|---|---|
| Circuits | Customers | Length (miles) | |
| 170 | 84,000 | 83.2 | $2,185 |

### 6.2.3 Estimated Costs – VMP

Tampa Electric and Accenture estimate that, in total, approximately 270 VM contract trimmers and six contract forestry inspectors will be needed for all distribution VM activities once the new initiatives are scaled up to their future steady state. The 69kV Reclamation Initiative will require approximately 40 VM total contract trimmers to complete.

## 6.3 Transmission Asset Upgrades

The Transmission Asset Upgrades Program is a systematic and proactive replacement Program of all Tampa Electric's remaining transmission wood poles with non-wood material. The company intends to complete this conversion from wood transmission poles to non-wood material poles during the timeframe of this initial ten-year SPP. Tampa Electric has over 25,400 transmission poles and structures with approximately 1,350 circuit miles of transmission facilities. Of these transmission structures, approximately 20 percent are supported with wood poles. Historically, the company's transmission hardening Program focused on replacing existing wood transmission poles with non-wood material upon a failed inspection. During replacement, the company would also upgrade existing hardware and insulators. From 2007 through 2019, the company hardened 8,971 wood transmission structures with non-wood material as a part of the existing Storm Hardening Plan. The company will continue to use the ongoing multiple transmission inspection methods to prioritize the replacement of existing wood transmission poles that fail inspection. Tampa Electric will also prioritize the systematic and proactive replacement of all other remaining wood transmission poles.

In the early 1990s, Tampa Electric made the decision to begin building all new transmission circuits with non-wood structures. Replacing all existing transmission wood poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, and more robust, wind loading standards than required at the time of installation. The Transmission Asset Upgrades Program will reduce restoration cost and outage times as a result of the anticipated reduction in the quantity of poles requiring replacement from an extreme weather event. Of the ten transmission poles replaced due to Hurricane Irma in 2017, nine were wood poles with no previously identified deficiencies that would warrant the pole to be replaced under the existing transmission hardening Program.

Tampa Electric used the 1898 & Co.'s resilience-based modeling to develop the initial prioritization of Projects. This initial prioritization is based upon the transmission circuit's historical performance relative to criticality of the transmission line, reducing customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. In order to account for technical and operational constraints like access and the long lead time for permits, the list was reviewed by Tampa Electric personnel for feasibility.

Once this review was complete a revised prioritization that incorporated access challenges, long lead time for permit requirements and scheduling constraints was developed. The revised prioritization is reflected in this ten-year SPP with Projects that are most feasible to implement accelerated into the first three years of the SPP. The remainder of the SPP years were scheduled by 1898 & Co.'s resilience-based model beginning in year 2023 to allow for scheduling, permitting and access issues to be addressed.

The table below shows the Transmission Asset Upgrades Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 21 | $5.6 |
| 2021 | 35 | $15.2 |
| 2022 | 28 | $15.0 |

The full detail of the supporting Transmission Asset Upgrades Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix "B".

## 6.4 Substation Extreme Weather Hardening

Tampa Electric's Substation Extreme Weather Hardening Program is designed to harden existing substations to minimize outages, reduce restoration times and enhance emergency response during extreme weather events. Hardening Projects within this Program could involve the installation of extreme weather protection barriers; installation of flood or storm surge prevention barriers; additions, modifications or relocation of substation equipment; modification to the designs of the company's substations; or other approaches identified to protect against extreme weather damage in or around the company's substations.

Tampa Electric engaged 1898 & Co. to perform preliminary analysis and prioritization of the company's 216 substations. The SLOSH model, described in the 1898 & Co. report included as

Appendix “F”, identified 59 of these 216 substations with some level of flooding risk and the height of a wall needed to mitigate that risk. The 59 substations were evaluated and prioritized in the model using only the single solution of building a flood wall around the perimeter of each substation. Using this methodology, the model identified 11 substations that were prioritized to be hardened within the 2020-2029 SPP.

Tampa Electric will begin this Program in early 2021 by engaging an additional third-party consultant that specializes in substation engineering and asset management to further identify and evaluate other potential hardening solutions beyond the single solution that was modeled. This study will include the 11 identified substations, as well as others that Tampa Electric subject matter experts determine have potential vulnerability to extreme weather. The study, to be completed by the end of 2021, will examine the potential for flooding for each substation, flood mitigation options, and provide an engineering recommendation for station flood protection or mitigation, if applicable. The study is estimated to cost $250,000 and will also include:

- High level cost estimates for the installation of a flood wall or other hardening solutions;
- Mitigation approaches and a scorecard based on prioritization of the hardening strategies intended to increase reliability; and
- An updated and refined prioritization list.

The Company expects the 2021 study and analysis to identify the proper hardening solution for each of the substations, with cost estimates that are more reflective of the unique characteristics of each substation. Once the study is complete, Tampa Electric will determine a final prioritized list of Substation Extreme Weather Protection Projects. The required Project-level information will be provided at the appropriate filing opportunity in the Storm Protection Plan Cost Recovery Clause Docket.

The table below shows the Substation Extreme Weather Hardening Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Substation Extreme Weather Hardening Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 0 | $0.0 |
| 2021 | 1 (Note 1) | $0.3 |
| 2022 | 0 | $0.0 |

Note 1: The Project identified in 2021 is the further study of potential substation solutions as described above.

### 6.5 Distribution Overhead Feeder Hardening

Tampa Electric's Distribution Overhead Feeder Hardening Program will strengthen the company's distribution system to withstand increased wind-loading and harsh environmental conditions associated with extreme weather events. This Program will provide the ability to reconfigure the electrical system to minimize the number of customers experiencing prolonged outages that may occur as a result of un-forecasted system conditions and unplanned circuit outages. The Distribution Overhead Feeder Hardening Program will focus on increasing the resiliency and sectionalizing capabilities of the distribution electrical system to better withstand extreme weather and minimize outages, outage durations and affected customer counts through two primary enhancements: Distribution Feeder Strengthening and Distribution Feeder Sectionalizing and Automation.

**6.5.1 Distribution Feeder Strengthening**

These enhancements will incorporate changes to the Company's distribution design standards to focus on the physical strength of Tampa Electric's distribution infrastructure. The company plans to harden selected feeders to meet NESC construction Grade B criteria with the Rule 250C (Extreme Wind) loading and strength criteria applied. This will involve the evaluation of the feeder, including a thorough review of the poles, conductor and equipment to determine the upgrades necessary to ensure the feeder meets new hardened design and construction standards.

**6.5.2 Distribution Feeder Sectionalizing and Automation**

These enhancements involve increasing the installation of automation equipment, reclosers, trip savers and other supporting sectionalizing infrastructure on existing distribution circuits. These devices provide many benefits that will improve the performance of the overall distribution system during extreme weather events such as:

- Allowing for the automatic transfer of load to neighboring feeders in the event of unplanned outages that can occur during both normal and extreme weather events;
- Allowing for the network to be re-configured automatically to minimize the number of customers experiencing prolonged outages during both normal and extreme weather events; and
- Reducing restoration time by isolating only those parts of the electrical system that contain faults that require assessment, investigation, follow-up and repair.

Upgraded conductor size will support the increased loading that could occur from such activity and provide additional ability to reconfigure the distribution system. Upgraded additional transformer capacity at strategic substations will ensure maximum load restoration capacity.

Combined, these design and standards changes will increase the overall resiliency of the company's feeder distribution system to withstand all ranges of extreme weather events.

Tampa Electric has approximately 800 distribution circuits, which were prioritized based on their reliability performance and priority customer count to identify the target circuits for the 2020-2022 timeframe. Reliability performance was considered for both extreme weather and blue-sky days with a higher weighting factor assigned to circuit reliability under extreme weather conditions.

With a list of (22) circuits targeted for an OH distribution investment, Tampa Electric identified improvements on each circuit that would result in increased sectionalizing of the system with the following measures:

- Target a 200-500 maximum customer range on each segment;
- Limit segment distance to two to three miles; and
- Limit serving between two to three MW of load on each segment.

For 2020 implementation, the company identified circuits for improvement that require minimal engineering, minimal lead-time on material and do not require permits. Circuit improvements that require complex engineering, longer lead-times for materials and could result in local and state permits and approval have been scheduled for 2021 and 2022 in-service dates. The remainder of the SPP years (2023-2029) were prioritized by the model.

The table below shows the Distribution Overhead Feeder Hardening Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 5 | $6.5 |
| 2021 | 18 | $15.4 |
| 2022 | 13 | $29.6 |

The full detail of the supporting Distribution Overhead Feeder Hardening individual Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix “D”.

### 6.6 Transmission Access Enhancement

The Transmission Access Enhancement Program is designed to ensure the company always has access to its transmission facilities for the performance of restoration. Immediate and permanent access to these facilities reduces restoration times and restoration costs. Increased power demands and changes in topography and hydrology related to customer development, along with several years of active storm seasons, have impacted the access to the existing transmission infrastructure. This Program will significantly enhance access to critical routes throughout the company’s transmission corridors that were impacted by these environmental and social changes. The Program is divided into two components: Access Roads and Access Bridges.

**Access Roads:** These Projects are designed to restore access to areas where changes in topography and hydrology have negatively impacted existing access roads or created the need to establish new access roads. The access roads are Tampa Electric’s primary route to critical transmission facilities for installation, maintenance, and repair. In addition, the FERC standard, FAC-003-4, requires that all utilities maintain a robust vegetation management Program for all high voltage circuits, 200kV and above. These routes are necessary to ensure compliance.

The company has identified a total of 70 potential Access Road Projects, subdivided by circuit. In many cases, more than one circuit benefits from the installation or repair of the road. While engineering will determine the exact scope and cost of the road, company subject matter experts developed a preliminary cost estimate for each Project that was used in the 1898 & Co. model for cost-benefit prioritization. The costs were based on the number of road miles and construction type. The total Access Roads initiative costs are detailed below for the 20 Access Road Projects proposed in the 2020-2029 SPP:

| **Access Road Projects Costs (in thousands)** | |
|---|---|
| **2020** | $0 |
| **2021** | $604 |
| **2022** | $391 |
| **2023** | $0 |
| **2024** | $810 |
| **2025** | $978 |
| **2026** | $0 |
| **2027** | $3,325 |
| **2028** | $1,982 |
| **2029** | $1,065 |

Government permitting is the primary driver of schedule, as the plan and approval process for a single permit can take up to twenty-four months. Since most proposed access roads are in low-lying or wetland areas, most will require review and approval from several agencies, e.g., State, County, Army Corps of Engineers. Permit fees and the associated mitigation costs are the most volatile cost variable. Actuals will be closely tracked, compared to estimates, and adjusted as necessary to ensure the Projects remain on budget.

**Access Bridges:** These Projects are designed to enhance or replace the company's current system of bridges used to access its "off road" transmission facilities. As with Access roads, access bridges are a primary route to critical transmission facilities for installation, maintenance, and repair. In addition, the FERC standard, FAC-003-4, requires all utilities to maintain a robust vegetation management Program for all high voltage circuits, 200kV and above. These routes are also necessary to ensure compliance. The last several storm seasons have impacted the integrity of the company's bridge network. While necessary repairs were made post-storm to ensure the bridges remain safe for travel, the repairs that were made were temporary to allow for a safe and timely restoration. Tampa Electric's system hardening activities place additional strain on the bridges. For example, the company's aggressive wooden pole replacement Program has created increases in bridge traffic and load from the heavier transmission vehicles needed to install the reinforced steel poles. The Access Bridge Project will bring the bridge(s) up to capacity to meet the current weight of the company's transmission vehicles and secure pilings and position in and over the waterways to ensure constant access to critical transmission infrastructure, particularly during extreme weather events.

The company currently maintains a total of 24 bridges, with three of these bridges being recently installed in a transmission upgrade Project. In addition to the 21 current bridges identified for replacement, the company identified an additional five bridges for a net total of 26 potential bridge Projects. The total Access Bridges initiative costs are detailed below for the 17 Access Bridge Projects proposed in the 2020-2029 SPP:

| Access Bridge Project Costs (in thousands) | |
|---|---|
| **2020** | $0 |
| **2021** | $780 |
| **2022** | $1,118 |
| **2023** | $1,606 |
| **2024** | $853 |
| **2025** | $360 |
| **2026** | $354 |
| **2027** | $0 |
| **2028** | $0 |
| **2029** | $601 |

Government permitting is the primary driver of schedule, as the plan and approval process for a single permit can take up to twenty-four months. The company expects all access bridges will require review and approval from several agencies, e.g., State, County, Army Corps of Engineers. Permit fees and associated mitigation costs are the most volatile cost variable. Actuals will be closely tracked, compared to estimates, and adjusted as necessary to ensure that each Project remains on budget.

Tampa Electric used 1898 & Co.'s resilience-based modeling described in Appendix "F" to evaluate the cost-benefit expectation for each of the 96 Access Enhancement Projects. Since permitting is the primary driver of the schedule, it was assumed that Access Projects could not begin until 2021. The model then developed a prioritization of these Projects based on the cost-benefit expectations. This SPP Plan reflects the completion of 37 Access Enhancement Projects over the ten-year SPP.

The table below shows the Transmission Access Enhancements Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Transmission Access Enhancements Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 0 | $0.0 |
| 2021 | 8 | $1.4 |
| 2022 | 6 | $1.5 |

**6.7 Infrastructure Inspections**

Tampa Electric’s Infrastructure Inspection Program is a comprehensive inspection Program that combines the existing Commission approved Storm Hardening Plan Initiatives of: Wood Pole Inspections, Transmission Structure Inspections, and the Joint Use Pole Attachment Audit.

The company originally developed the wooden pole inspection initiative to comply with Order No. PSC-06-0144-PAA-EI, which requires each investor-owned electric utility to implement an inspection Program for its wooden transmission and distribution poles on an eight-year cycle based on the requirements of the NESC. The company developed the transmission structure inspection and joint-use attachment audit initiatives to comply with Commission Order No. PSC-06-0351-PAA-EI.

Tampa Electric has not historically attempted to quantify the benefits of these inspection activities because they were required by Commission Order. In those Orders, the Commission found that these activities offered significant storm resiliency benefits. For instance, the Commission found that wood pole inspections and corrective maintenance “can reduce the impact of hurricanes and tropical storms upon utilities’ transmission and distribution systems.” Order No. PSC-06-0144-PAA-EI. The Commission also found that wood pole inspections reduce restoration times because, in the named storms in Florida in 2004 and 2005, “the number of failed poles resulting from a storm [were] correlated with the number of days required to restore service to customers.” Order No. PSC-06-0144-PAA-EI. The Commission later found that a transmission structure inspection program would offer similar benefits. Order No. PSC-06-0351-PAA-EI. The Commission also found that a joint use attachment audit would provide storm resiliency benefits because “[u]tility poles that are overloaded or approaching overloading are subject to failure in extreme weather.” Order No. PSC-06-0351-PAA-EI. Tampa Electric believes that infrastructure inspection activities still offer these benefits.

Tampa Electric also believes that the costs of these activities are outweighed by their benefits. In Order No. PSC-06-0144-PAA-EI, the Commission analyzed the potential costs of a mandatory wooden pole inspection program and concluded: “The cost of conducting these inspections, while not insignificant, must be compared to the storm restoration costs incurred in 2004 and 2005.” Order No. PSC-06-0144-PAA-EI. Tampa Electric agrees with this assessment and concludes that the costs of infrastructure inspections are outweighed by the associated reduction in restoration costs and outage times identified by the Commission.

### 6.7.1 Wood Pole Inspections

Tampa Electric's Wood Pole Inspection Initiative is part of a comprehensive program initiated by the FPSC for Florida investor-owned electric utilities to harden the electric system against severe weather.

This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI which requires each investor-owned electric utility to implement an inspection program of its wooden transmission and distribution poles on an eight-year cycle based on the requirements of the NESC. This program provides a systematic identification of poles that require repair, reinforcement or replacement to meet strength requirements of the NESC.

The wood pole inspections will be conducted on a substation circuit basis with a goal of inspecting the entire wood pole population every eight years. An average of 36,000 wooden distribution poles will be inspected annually with each pole receiving a visual inspection, a sound & bore procedure and a groundline/excavation inspection (except for chromated copper arsenate “CCA” poles less than 16 years of age.)

Tampa Electric estimates that this initiative will cost approximately $1,000,000 annually over the ten-year horizon of this SPP.

Tampa Electric’s wood pole inspection strategy takes a balanced approach and has produced excellent results in a cost-effective manner. The future inspections coupled with the company’s pole replacement activities will ultimately harden Tampa Electric’s distribution system.

### 6.7.2 Transmission Inspections

Tampa Electric will continue to conduct the multi-pronged inspection approach the company has historically applied to the system which has led to the transmission system having a history of strong reliability performance. This approach includes the eight-year above ground structure inspection cycle, eight-year ground line wood inspection cycle, annual ground patrol, annual aerial infrared patrol, annual substation inspection cycle and the pre-climb inspection requirement. Tampa Electric will continue these inspections and will also continue the company’s ongoing efforts to monitor and evaluate the appropriateness of its transmission structure inspection program to ensure that any cost-effective storm hardening or reliability opportunities found are taken advantage of.

Tampa Electric estimates the annual cost of this initiative is approximately $360,000 over the ten-year Plan horizon. Tampa Electric believes this cost is justified because the Commission previously found that a robust transmission inspection program was necessary.

#### 6.7.2.1 Groundline Inspections

Tampa Electric conducts groundline inspections in compliance with the Commission's order requiring groundline inspection of wooden transmission structures. A groundline inspection includes excavation, sounding and boring wood poles. Excavation requires removing earth at the base of the pole around the entire circumference to a minimum depth of 18 inches below groundline. All poles passing the excavation inspection will then be sounded with a hammer. If sounding provides evidence of possible interior voids or rot, at least one boring shall be made where the void is indicated. If rot or voids are detected, enough boring shall be made so that the extent can be determined. Poles set in concrete, or otherwise inaccessible below groundline, shall be bored at least twice at groundline at a 45-degree downward direction. All bored holes shall be plugged with treated dowels. Groundline inspections are performed on an eight-year cycle. Each year approximately 12.5 percent of all wooden transmission structures are scheduled for inspection. For 2020 through 2022, the company plans to perform approximately 1,750 groundline inspections over the three-year period.

#### 6.7.2.2 Ground Patrol

The ground patrol is a visual inspection for deficiencies including poles, insulators, switches, conductors, static wire and grounding provisions, cross arms, guying, hardware and encroachment. The ground patrol will include identification of vegetation encroachment as well as all circuit deficiencies. All transmission circuits are patrolled by ground at least once each year.

#### 6.7.2.3 Aerial Infrared Patrol

The aerial infrared patrol is planned annually on the entire transmission system. It is performed by helicopter with a contractor specializing in thermographic power line inspections and a company employee serving as navigator and observer. This inspection identifies areas of concern that are not readily identifiable by normal visual methods as well as splices and other connections that are heating abnormally and may result in premature failure of the component. This inspection also identifies obvious system deficiencies such as broken cross arms and visibly damaged poles. Since many of these structures are on limited access ROW, this aerial inspection provides a frequent review of the entire transmission system and helps identify potential reliability issues in a timely manner.

#### 6.7.2.4 Above Ground Inspections

Above ground inspections are performed on transmission structures on an eight-year cycle; therefore, each year approximately 12.5 percent or one-eighth of transmission structures are inspected. This inspection will be performed by either an internal team member or contractor specializing in above ground power pole inspections and may be performed by climbers, bucket truck, helicopter or Unmanned Aerial Systems (“UAS” or Drones). The above ground inspection is a comprehensive inspection that includes assessment of poles, insulators, switches, conductors, static wire, grounding provisions, cross arms, guying, hardware and encroachment issues. This program provides a detailed review of the above ground condition of the pole and the associated hardware on the structure. Due to advances in technology, the capabilities of

UAS has allowed the company to complete the Above Ground Inspections in conjunction with the Ground Patrol utilizing the UAS for an aerial view of the structures identified for the comprehensive inspection.

For 2020 through 2022, annual above ground inspections are planned on approximately 10,500 structures. This is in line with the company's petition that changed the above ground inspection cycle from a six-year cycle to an eight-year cycle which was approved in Docket 20140122-EI, Order No. PSC-14-0684-PAA-EI and confirmed by Consummating Order No. PSC-15-0017-CO-EI.

#### 6.7.2.5 Substation Inspections

Tampa Electric performs inspections of distribution substations annually and inspections of transmission substations quarterly. The substation inspections include visual inspection of the substation fence, equipment, structures, control buildings and the integrity of grounding system for all equipment and structures.

Tampa Electric estimates that the annual cost of these inspections is approximately $150,000 over the ten-year horizon of the SPP.

#### 6.7.2.6 Pre-Climb Inspections

Tampa Electric crews are required to inspect wooden transmission & distribution poles prior to climbing. As part of these inspections, the employee is required to visually inspect each pole prior to climbing and sound each pole with a hammer if deemed necessary. These pre-climbing inspections serve to provide an additional safety-oriented integrity check of poles prior to the employee ascending the pole and may also result in the identification of any structural deterioration issues.

There are no costs associated with this activity since it occurs only when an employee is climbing a pole for another purpose.

**6.7.3 Joint Use Pole Attachments Audit**

Tampa Electric will continue to conduct comprehensive loading analyses to ensure the company's poles with joint use attachments are not overloaded and meet the NESC or Tampa Electric Standards, whichever is more stringent. These loading analyses are a direct effort to lessen storm related issues on poles with joint use attachments. All current joint use agreements require attaching entities to apply for and gain permission to make attachments to Tampa Electric's poles. Once the application is received, an engineering assessment of every pole where attachments are being proposed will have a comprehensive loading analysis performed. If the loading analysis determines that additional support is necessary, all upgrades will be made prior to notifying the joint use attacher that their construction is ready for attachments.

Tampa Electric's audit of joint use attachments is an important step in documenting all pole attachments. A critical component of the audit is finding pole attachments that the company is not aware of. If an unauthorized attachment is found, the company can perform a comprehensive pole loading analysis to ensure the pole is not overloaded and ensuring that all safety, reliability, capacity and engineering requirement are met.

The necessity for the audit arises due to the significant wind loading and stress that pole attachments can have on a pole and the fact that some attachments are made without notice or prior engineering.

There is no incremental cost of this initiative as each audit is ultimately paid for by the joint attacher.

### 6.7.4 Infrastructure Inspections Summary

The Infrastructure Inspection Program has no estimated completion date because the inspection activities are continuous and ongoing. The infrastructure inspection activities are either part of an ongoing cycle – such as wood pole and transmission structure inspections – or only occur when triggered by a specific event – such as pre-climb and joint use inspections. Given the nature of this Program, Tampa Electric concluded that it was not practical or feasible to identify specific Storm Protection Projects under this Program. Instead, the table below shows the number of infrastructure inspections the company is projecting over the 2020-2022 storm Protection Plan period.

| **Projected Number of Infrastructure Inspections** | | | |
|---|---|---|---|
| | **2020** | **2021** | **2022** |
| **Joint Use Audit** | Note 1 | | |
| **Distribution** | | | |
| Wood Pole Inspections | 22,500 | 22,500 | 35,625 |
| Groundline Inspections | 13,275 | 13,275 | 21,018 |
| **Transmission** | | | |
| Wood Pole/Groundline Inspections | 702 | 367 | 707 |
| Above Ground Inspections | 2,949 | 3,895 | 3,396 |
| Aerial Infrared Patrols | Annually | Annually | Annually |
| Ground Patrols | Annually | Annually | Annually |
| Substation Inspections | Annually | Annually | Annually |

Note 1: Tampa Electric completed its most recent Joint Use Pole Attachment Audit in the first quarter of 2020.

The table below provides the annual O&M expenses for each of the inspection programs for the 2020-2022 period.

| Projected Costs of Infrastructure Inspections (in thousands) | | | |
|---|---|---|---|
| | 2020 | 2021 | 2022 |
| **Distribution** | | | |
| Wood Pole/Groundline Inspections | $708 | $1,000 | $1,020 |
| **Transmission** | | | |
| Wood Pole/Groundline Inspections | $60 | $61 | $62 |
| Above Ground Inspections | $10 | $10 | $10 |
| Aerial Infrared Patrols | $110 | $112 | $114 |
| Ground Patrols | $145 | $148 | $151 |
| Substation Inspections | $140 | $143 | $146 |

## 6.8 Legacy Storm Hardening Plan Initiatives

The final category of storm protection activities consists of those legacy Storm Hardening Plan Initiatives that are well-established and steady state and for which the company does not propose any specific Storm Protection Projects at this time. Tampa Electric will continue these activities because the company believes they continue to offer the storm resiliency benefits identified by the Commission in Order No. PSC-06-0351-PAA-EI, which required the company to perform these activities. Tampa Electric cannot offer an estimated completion date for this Program because the initiatives are still mandated by the Commission and because the initiatives are all integrated into the company’s ongoing operations. Historically, Tampa Electric has not performed a formal cost benefit analysis for these activities because they were mandated by the Commission. Instead, the company evaluated projects under these initiatives based upon potential negative impacts on public safety and health, magnitude of impact on customers likely affected by an outage, environmental impacts, and access constraints that may exist following a potential major storm. Once the company selected a storm hardening project, Tampa Electric would then perform an internal formal cost analysis prior to initiating the project. In this internal analysis, the company would project the costs and estimate the benefits that should be realized. Tampa Electric recognizes that assigning a monetary value to customer benefits is challenging due to the lack of specific information about the financial impacts of outages, and because assigning value to public safety and health may skew the project's benefit analysis.

**6.8.1 Geographic Information System**

Tampa Electric's Geographic Information System ("GIS") will continue to serve as the foundational database for all transmission, substation and distribution facilities. Development and improvement of the GIS continues. All new computing technology requests and new initiatives are evaluated with a goal to eliminate redundant, exclusive and difficult to update databases as well as to place emphasis on full integration with Tampa Electric's business processes. These evaluations further cement GIS as the foundational database for Tampa Electric's facilities.

Tampa Electric does not propose any GIS Storm Protection Projects over the ten-year planning horizon. The company will, however, continue ongoing activities to improve the functionality and ease of use of the GIS for the company's GIS users. Two examples of these ongoing activities include the GIS User's Group, which meets to review, evaluate and recommend enhancements for implementation. The second ongoing activity is the annual publication of the Tampa Electric GIS Annual Report. Tampa Electric does not propose any specific Storm Protection Projects due to the reasons identified above.

Tampa Electric estimates the annual cost of maintaining and operating the GIS Program is $0 because the company's GIS system is an integral system used by the company to maintain its transmission and distribution asset information. Tampa Electric will continue to update and make improvements/enhancements to its GIS as needed.

### 6.8.2 Post-Storm Data Collection

Tampa Electric has implemented a formal process to randomly sample system damage following a major weather event in a statistically significant manner. This information will be used to perform forensic analysis to categorize the root cause of equipment failure. From these reports, recommendations and possible changes will be made regarding engineering, equipment and construction standards and specifications. A hired third party of data collection specialists will patrol a representative sample of the damaged areas of the electric system following a major storm event and perform the data collection process. At a minimum, the following types of information will be collected:

- Pole/Structure – type of damage, size and type of pole, and likely cause of damage;
- Conductor – type of damage, conductor type and size, and likely cause of damage;
- Equipment – type of damage, overhead or underground, size, and likely cause of damage; and
- Hardware – type of damage, size and likely cause of damage.

Third party engineering personnel will perform the forensic analysis of a representative sample of the data obtained to evaluate the root cause of failure and assess future preventive measures where possible and practical. This may include evaluating the type of material used, the type of construction and the environment where the damage occurred including existing vegetation and elevations. Changes may be recommended and implemented if more effective solutions are identified by the analysis team.

The company does not propose any specific post-storm data collection Projects under this Program because there will only be post-storm data collection activity if a major weather event occurs, and the company cannot predict when or if those events will occur during the ten-year planning horizon.

The incremental cost of this initiative is estimated to be approximately $113,000 per storm and will depend on the severity of the storm and extent of system damage.

### 6.8.3 Outage Data - Overhead and Underground Systems

Tampa Electric tracks and stores the company’s outage data for overhead and underground systems in a single database called the Distribution Outage Database (“DOD”). The DOD is linked to and receives outage data from the company’s EMS and OMS. The DOD tracks outage records according to cause and equipment type and can support the following functionality:

- Centralized capture of outage related data;
- Analysis and clean-up of outage-related data;
- Maintenance and adjustment to distribution outage database data;
- Automatic Generation and distribution of canned reliability reports; and
- Generating ad hoc operational and managerial reports.

The DOD is further programmed to distinguish between overhead and underground systems and is specifically designed to generate distribution service reliability reports that comply with Rule 25-6.0455, F.A.C.

In addition to the DOD and supporting processes, the company’s overhead and underground systems are analyzed for accurate performance. The company also has established processes in place for collecting post-storm data and performing forensic analysis to ensure the performance of Tampa Electric’s overhead and underground systems are correctly assessed.

The company does not propose any specific DOD Projects because there will only be DOD activity when there are storm related outages, and the company cannot predict when storm-related outages will occur during the ten-year planning horizon.

Tampa Electric does not forecast any annual DOD-related expenditures over the ten years of the SPP because costs are only incurred during a storm. The cost of this initiative is estimated to be approximately $100,000 per storm.

### 6.8.4 Increase Coordination with Local Governments

Tampa Electric representatives will continue to focus on maintaining existing vital governmental contacts and participating on disaster recovery committees to collaborate in planning, protection, response, recovery and mitigation efforts. In addition, Tampa Electric representatives will continue to communicate and coordinate with local governments on vegetation management, search and rescue operations, debris clearing, and identification of critical community facilities. Tampa Electric will participate with local and municipal government agencies within its service area, as well as the FDEM, in planning and facilitating joint storm exercises. In addition, Tampa Electric will continue to be involved in improving emergency response to vulnerable populations.

The company does not propose any specific local government coordination Projects because these activities occur intermittently and often on an unplanned basis before, during, and after severe weather events.

There are no incremental costs associated with this activity.

#### 6.8.5 Collaborative Research

Tampa Electric will continue the company’s participation in collaborative research effort with Florida’s other investor-owned electric utilities, several municipals and cooperatives to further the development of storm resilient electric utility infrastructure and technologies that reduce storm restoration costs and outages to customers.

This collaborative research is facilitated by the Public Utility Research Center (“PURC”) at the University of Florida. A steering committee comprised of one member from each of the participating utilities provides the direction for research initiatives. Tampa Electric signed an extension of the memorandum of understanding with PURC in December 2018, effective January 1, 2019, for two years. The memorandum of understanding will automatically extend for successive two-year terms on an evergreen basis until the utilities and PURC agree to terminate the agreement.

The company does not propose any specific collaborative research Projects over the ten-year period of the SPP. Tampa Electric does not estimate that there will be any collaborative research costs over the same ten-year horizon.

#### 6.8.6 Disaster Preparedness and Recovery Plan

A key element in minimizing storm-caused outages is having a natural disaster preparedness and recovery plan. A formal disaster plan provides an effective means to document lessons learned, improve disaster recovery training, pre-storm staging activities, and post-storm recovery. The Commission’s Order No. PSC-06-0351-PAA-E1, issued on April 25, 2006, within Docket No. 20060198-E1 required each investor-owned electric utility to develop a formal disaster preparedness and recovery plan that outlines its disaster recovery procedures and maintain a current copy of its utility disaster plan with the Commission.

Tampa Electric will continue to be active in many ongoing activities to support the restoration of the system before, during and after storm activation. The company will continue to lead or support disaster preparedness and recovery plan activities such as planning, training and working with other electric utilities and local government to continually refine and improve the company's ability to respond quickly and efficiently in any restoration situation.

Tampa Electric's Emergency Management plans address all hazards, including extreme weather events and are reviewed annually. Tampa Electric follows the policy set by TECO Energy for Emergency Management and Business Continuity which delineates responsibilities at the employee, company and community levels.

Tampa Electric will also continue to plan, participate in, and conduct internal and external preparedness exercises, collaborating with government emergency management agencies, at the local, state and federal levels. Internal company exercises focus on testing lessons learned from prior exercises/activations, new procedures, and educating new team members on roles and responsibilities in the areas of incident command, operations, logistics, planning and finance. The scope and type of internal exercises vary from year to year based on exercise objectives defined by a cross-functional exercise design team, following the Homeland Security Exercise and Evaluation Program ("HSEEP"). External preparedness exercises are coordinated by local, state and federal governmental emergency management agencies. Tampa Electric personnel participate in these exercises to test the company's internal emergency response plans, including coordination with Emergency Support Functions ("ESF") to maintain key business relationships at local Emergency Operation Centers ("EOC"). Like Tampa Electric, the exercise type (tabletop, functional or full-scale) and scope varies from year to year, and depending upon the emergency management agencies’ exercise objectives, Tampa Electric participants may not be included.

Annually, Tampa Electric participates in the State of Florida’s hurricane exercise with the FPSC, which often coincides with exercises conducted by Hillsborough, Pasco, Pinellas and Polk counties. In addition, municipalities within Tampa Electric’s service area (Oldsmar, Plant City, Tampa and Temple Terrace) may also host exercises and/or pre-storm season briefings. For example, in 2019, Tampa Electric participated in exercises and/or pre-storm briefings hosted by the State of Florida (in conjunction with FPSC), Hillsborough and Pinellas counties, as well as the cities of Oldsmar, Tampa and Temple Terrace. However, in 2020, Tampa Electric has been advised that the State of Florida will not conduct an annual hurricane exercise. As a result, some counties and municipalities are following the State’s lead.

Tampa Electric has been incorporating Lessons Learned from Hurricane Irma and the company’s experience supporting the restoration for Hurricane Michael into the company’s Emergency Response plans. While the updates cover a broad category or processes, a focus has been on insuring the plan can scale up to handle major storms (Cat 3, 4, 5), in Logistics (life support) and the ability to restore internal communications in the event public networks are negatively impacted (Internet, cellular and satellite).

Tampa Electric will implement a Damage Assessment tool as an integrated part of its Advanced Distribution Management System (“ADMS”) scheduled for implementation in 2021.

The total cost to support all Emergency Management activities and initiatives is estimated to be $300,000 annually.

### 6.8.7 Distribution Pole Replacements

Tampa Electric's distribution pole replacement initiative starts with the company's wood pole inspections and includes designing, utilizing conductors and/or supporting structures, and constructing distribution facilities that meet or exceed the company's current design criteria for the distribution system. The company will continue to appropriately address all poles identified through its Infrastructure Inspection Program.

Given that this is a reactive activity (poles are replaced or restored only when they fail an inspection), Tampa Electric concluded that it was not practical or feasible to identify specific distribution pole replacement Storm Protection Projects.

Tampa Electric estimates the annual capital and O&M costs of this initiative is approximately $13,300,000 over the ten-year Plan horizon.

### 6.8.8 Legacy Storm Hardening Plan Initiatives Costs

The table below shows the projected costs for the first three years of the 2020-2029 SPP for the Legacy Storm Hardening Plan Initiatives:

| | Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions) | |
|---|---|---|
| | Disaster Preparedness and Recovery Plan | Distribution Pole Replacements |
| 2020 | $0.3 | $9.9 |
| 2021 | $0.3 | $11.8 |
| 2022 | $0.3 | $15.5 |

# 7 Storm Protection Plan Projected Costs and Benefits

Tampa Electric developed the projected 2020-2029 SPP costs by examining the time, the scope of work, and reasonably expected costs for each of the SPP Programs. To develop the company's estimations of costs, Tampa Electric relied upon the following key underlying assumptions:

1. Initially, the company identified the level of work and associated costs that could be successfully managed and physically performed annually to improve storm performance. This initially was determined to be between 100 to 200 million dollars on an annual basis, based upon work constraints.
2. Recognizing the sustained amount of work it would take for external resource companies to physically build or obtain a work force that could support several ongoing Storm Protection Programs.
3. Recognizing that there will be some competition for resources between utilities which could push costs upward.
4. Identification of the range of work necessary for each Storm Protection Program and the feasibility of success with external resources.
5. The costs would be made up of new incremental capital and O&M costs for each of the proposed Storm Protection Programs and their associated Projects.
6. Tampa Electric and 1898 & Co. ran unconstrained modeling which optimized the company's 2020-2029 spend at approximately $1.5 billion over the ten-year Plan.
7. Tampa Electric and 1898 & Co. ran constrained modeling which further supported the annual optimal spend to be between 100 to 200 million on an annual basis.
8. Actual historical costs would be used where the company has significant history and recent experience in developing the cost for each type of Project. Costs were also analyzed for impacts for potential competition and

future contractor capacity impacts.

9. Costs were validated for reasonableness and range by a variety of means, either in discussions amongst internal team members with this experience, discussions with Accenture LLP and 1898 & Co., or discussions with neighboring utilities.
10. Costs were used to complete SPP programs within the designated proposed timeline as described in the Transmission Asset Upgrade Program and the 69kV Reclamation initiative within the Vegetation Management Program.
11. Recognizing costs were projected based upon single solution modeling for the Substation Extreme Weather Hardening Program. The company needs to evaluate other potential solutions and opportunities before committing to an appropriate cost-effective solution for Tampa Electric’s substations.
12. The company will continue the components of the Commission’s legacy Storm Hardening Plan and will seek recovery of the costs associated with these activities through the SPPCRC, with the exception of the Geographical Information System, Post-Storm Data Collection, Increased Coordination with Local Governments, Disaster Preparedness and Recovery Plan, Distribution Pole Replacements, and unplanned (reactive) vegetation management.
13. The company would show with transparency the total costs for the proposed 2020-2029 SPP, the total revenue requirements for the proposed 2020-2029 SPP, and the total revenue requirements which would be recoverable through the Storm Protection Plan Cost Recovery Clause.

The table below provides Tampa Electric’s projected 2020-2029 Storm Protection Plan total costs (capital and O&M) by Programs:

| Tampa Electric's 2020-2029 Storm Protection Plan Total Costs by Program (in Millions) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Capital** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
| **Distribution Lateral Undergrounding** | $8.00 | $79.45 | $108.08 | $101.44 | $107.00 | $110.78 | $113.96 | $111.42 | $115.52 | $121.17 | $976.81 |
| **Transmission Asset Upgrades** | $5.50 | $15.21 | $14.98 | $16.51 | $11.99 | $19.04 | $17.92 | $16.28 | $19.56 | $12.11 | $149.12 |
| **Substation Extreme Weather Protection** | $0.00 | $0.00 | $0.00 | $0.00 | $7.34 | $5.54 | $4.67 | $6.71 | $5.24 | $2.88 | $32.37 |
| **Distribution Overhead Feeder Hardening** | $6.50 | $15.38 | $29.58 | $33.39 | $32.49 | $33.19 | $33.82 | $32.76 | $36.36 | $36.25 | $289.73 |
| **Transmission Access Enhancements** | $0.00 | $1.38 | $1.52 | $1.56 | $1.66 | $1.40 | $0.54 | $3.17 | $1.93 | $1.57 | $14.73 |
| **Distribution Pole Replacements** | $9.42 | $11.18 | $14.72 | $15.16 | $15.62 | $16.09 | $10.64 | $10.86 | $11.07 | $11.29 | $126.05 |
| **O&M** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
| **Distribution Vegetation Management - planned** | $16.49 | $19.76 | $21.18 | $24.00 | $24.22 | $25.55 | $26.77 | $27.99 | $29.42 | $30.94 | $246.31 |
| **Distribution Vegetation Management - unplanned** | $1.30 | $1.30 | $1.20 | $1.10 | $1.10 | $1.10 | $1.20 | $1.20 | $1.30 | $1.30 | $12.10 |
| **Transmission Vegetation Management - planned** | $2.63 | $3.53 | $3.59 | $3.66 | $3.04 | $3.13 | $3.23 | $3.30 | $3.38 | $3.46 | $32.95 |
| **Transmission Vegetation Management - unplanned** | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| **Transmission Asset Upgrades** | $0.11 | $0.30 | $0.30 | $0.33 | $0.24 | $0.38 | $0.36 | $0.33 | $0.39 | $0.24 | $2.98 |
| **Distribution Overhead Feeder Hardening** | $0.21 | $0.38 | $0.40 | $0.79 | $0.82 | $1.02 | $1.06 | $1.17 | $1.42 | $1.64 | $8.92 |
| **Distribution Infrastructure Inspections** | $0.71 | $1.00 | $1.02 | $1.04 | $1.06 | $1.08 | $1.10 | $1.13 | $1.15 | $1.17 | $10.46 |
| **Transmission Infrastructure Inspections** | $0.47 | $0.47 | $0.48 | $0.49 | $0.50 | $0.51 | $0.52 | $0.53 | $0.54 | $0.56 | $5.09 |
| **SPP Planning & Common** | $0.99 | $0.39 | $0.20 | $0.20 | $0.21 | $0.21 | $0.22 | $0.22 | $0.22 | $0.23 | $3.10 |
| **Other Legacy Storm Hardening Plan Items** | $0.28 | $0.28 | $0.29 | $0.29 | $0.30 | $0.30 | $0.31 | $0.32 | $0.32 | $0.33 | $3.01 |
| **Distribution Pole Replacements** | $0.52 | $0.62 | $0.81 | $0.83 | $0.86 | $0.88 | $0.59 | $0.60 | $0.61 | $0.62 | $6.93 |

Tampa Electric developed the 2020-2029 SPP projected costs and benefits for each of the proposed SPP Programs through the thorough and comprehensive analysis the company performed with Accenture LLP and 1898 & Co. Accenture, as described above, modeled the current VM Program against the proposed SPP initiatives during extreme weather. For the other SPP Programs, Tampa Electric worked with 1898 & Co. to evaluate the benefits of the 10-year Programs against a status quo scenario. Both the reduction in restoration costs and the reduction in customer minutes of interruption show the percentage improvement expected during major event days from the SPP Programs when compared to the status quo.

**Tampa Electric - Proposed 2020-2029 Storm Protection Plan**
**Projected Costs versus Benefits**

| Storm Protection Program | Projected Costs (in Millions) | | Projected Reduction in Restoration Costs (Approximate Benefits in Percent) | Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent) | Program Start Date | Program End Date |
|---|---|---|---|---|---|---|
| | Capital | O&M | | | | |
| Distribution Lateral Undergrounding | $976.8 | $0.0 | 33 | 44 | Q2 2020 | After 2029 |
| Vegetation Management | $0.0 | $279.3 | 21 | 22 to 29 | Q2 2020 | After 2029 |
| Transmission Asset Upgrades | $148.9 | $3.0 | 90 | 13 | Q2 2020 | 2029 |
| Substation Extreme Weather | $32.4 | $0.0 | 70 to 80 | 50 to 65 | Q1 2021 | After 2029 |
| Distribution Overhead Feeder | $289.7 | $8.9 | 38 to 42 | 30 | Q2 2020 | After 2029 |
| Transmission Access Enhancements | $14.8 | $0.0 | 10 | 74 | Q1 2021 | After 2029 |

Tampa Electric developed the estimated annual jurisdictional revenue requirements with cost estimates for each of the proposed 2020-2029 SPP Programs plus depreciation and return on

SPP, as outlined in Rule 25-6.030 F.A.C. The estimated annual jurisdictional revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures using the depreciation rates from Tampa Electric's most current depreciation study. In addition, the depreciation expense has been reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the SPP capital Projects. Lastly, in accordance with the FPSC Order No. PSC-12-0425-PAA-EU, from the company's 2012 Stipulation and Settlement Agreement, Tampa Electric calculated a return on the undepreciated balance of the asset costs at a weighted average cost of capital using the return on equity from the May 2019 Actual Surveillance Report. Only capital expenditures for SPP Projects after April 10, 2020 were included in the depreciation and return on asset calculations included in the estimated annual jurisdictional revenue requirements.

The table below provides Tampa Electric's projected 2020-2029 Storm Protection Plan total revenue requirements (capital and O&M) by Program:

| Tampa Electric's 2020-2029 Storm Protection Plan Total Revenue Requirements by Program (in Millions) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Capital** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
| **Distribution Lateral Undergrounding** | $0.19 | $4.66 | $13.83 | $23.93 | $33.76 | $43.83 | $54.01 | $64.01 | $73.84 | $83.91 | $395.97 |
| **Transmission Asset Upgrades** | $0.14 | $1.25 | $2.69 | $4.16 | $5.45 | $6.82 | $8.45 | $9.91 | $11.40 | $12.66 | $62.93 |
| **Substation Extreme Weather Protection** | $0.00 | $0.00 | $0.00 | $0.00 | $0.28 | $0.95 | $1.42 | $1.93 | $2.47 | $2.82 | $9.87 |
| **Distribution Overhead Feeder Hardening** | $0.14 | $1.33 | $3.42 | $6.33 | $9.30 | $12.19 | $15.06 | $17.83 | $20.64 | $23.53 | $109.77 |
| **Transmission Access Enhancements** | $0.00 | $0.06 | $0.19 | $0.33 | $0.48 | $0.61 | $0.69 | $0.85 | $1.07 | $1.22 | $5.50 |
| **Distribution Pole Replacements** | $0.25 | $1.41 | $2.60 | $3.96 | $5.32 | $6.69 | $7.79 | $8.61 | $9.42 | $10.22 | $56.27 |
| **O&M** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
| **Distribution Vegetation Management - planned** | $16.49 | $19.76 | $21.18 | $24.00 | $24.22 | $25.55 | $26.77 | $27.99 | $29.42 | $30.94 | $246.31 |
| **Distribution Vegetation Management - unplanned** | $1.30 | $1.30 | $1.20 | $1.10 | $1.10 | $1.10 | $1.20 | $1.20 | $1.30 | $1.30 | $12.10 |
| **Transmission Vegetation Management - planned** | $2.63 | $3.53 | $3.59 | $3.66 | $3.04 | $3.13 | $3.23 | $3.30 | $3.38 | $3.46 | $32.95 |
| **Transmission Vegetation Management - unplanned** | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| **Transmission Asset Upgrades** | $0.11 | $0.30 | $0.30 | $0.33 | $0.24 | $0.38 | $0.36 | $0.33 | $0.39 | $0.24 | $2.98 |
| **Distribution Overhead Feeder Hardening** | $0.21 | $0.38 | $0.40 | $0.79 | $0.82 | $1.02 | $1.06 | $1.17 | $1.42 | $1.64 | $8.92 |
| **Distribution Infrastructure Inspections** | $0.71 | $1.00 | $1.02 | $1.04 | $1.06 | $1.08 | $1.10 | $1.13 | $1.15 | $1.17 | $10.46 |
| **Transmission Infrastructure Inspections** | $0.47 | $0.47 | $0.48 | $0.49 | $0.50 | $0.51 | $0.52 | $0.53 | $0.54 | $0.56 | $5.09 |
| **SPP Planning & Common** | $0.99 | $0.39 | $0.20 | $0.20 | $0.21 | $0.21 | $0.22 | $0.22 | $0.22 | $0.23 | $3.10 |
| **Other Legacy Storm Hardening Plan Items** | $0.28 | $0.28 | $0.29 | $0.29 | $0.30 | $0.30 | $0.31 | $0.32 | $0.32 | $0.33 | $3.01 |
| **Distribution Pole Replacements** | $0.52 | $0.62 | $0.81 | $0.83 | $0.86 | $0.88 | $0.59 | $0.60 | $0.61 | $0.62 | $6.93 |

# 8 Storm Protection Plan Estimated Rate Impacts

Tampa Electric prepared estimated rate impacts of the Storm Protection Plan for 2020, 2021, 2022 and 2023. While there are not going to be any billed rate impacts during 2020, the 2020 costs have been calculated separately from the 2021 costs so the impact of each year on the 2021 rate impacts is clear. This is because the 2020 costs will be recovered at the same time as the 2021 costs through the Storm Protection Plan Cost Recovery Clause ("SPPCRC") rates initiating in January 2021.

Each year's costs derive from the SPP Programs described in this Plan and are the capital and O&M costs combined into a revenue requirement. For each year, the SPP Programs were itemized and identified as to whether they are substation, transmission or distribution costs. Each of those functionalized costs were then allocated to the appropriate rate class using the allocation factors for that function.

The allocation factors used were from the Tampa Electric's 2013 Cost of Service Study prepared in Docket No. 20130040-EI which was used for the current company's base rate design. Using these factors assures that the incremental SPP costs are being recovered from customers in the same manner as the comparable costs included in base rates are being recovered through current base rates.

Once the total SPP revenue requirement recovery allocation to the rate classes was derived, the clause rates were determined in the same manner as current clause rates are designed.

For Residential, the charge is a kWh charge. For both Commercial and Industrial, the charge is a kW charge. The charges are derived by dividing the rate class allocated SPP revenue requirements by the most recent 2020 energy billing determinants (for residential) and by the most recent 2020 demand billing determinants (for commercial and industrial). Those clause charges were then applied to the billing determinants associated with typical bills for those groups to calculate the impact on those bills. This was done using a combination of 2020 and 2021 costs for the 2021 bills, and for each year 2022 and 2023 for those bills.

A similar procedure will be used to derive actual clause charges in the clause cost recovery docket to come this summer, but in that case applied to all rate classes and using 2021 projected billing determinants.

The following table shows the full rate impact of the SPP on typical bills:

| | **Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)** | | | |
|---|---|---|---|---|
| | **Customer Class** | | | |
| | Residential 1000 kWh | Residential 1250 kWh | Commercial 1 MW 60 percent Load Factor | Industrial 10 MW 60 percent Load Factor |
| 2020 | 1.50 | 1.48 | 1.44 | 0.55 |
| 2021 | 2.22 | 2.21 | 2.14 | 0.84 |
| 2022 | 3.09 | 3.06 | 2.98 | 1.13 |
| 2023 | 4.12 | 4.07 | 3.95 | 1.46 |

The rate impacts presented above reflect the total cost of the SPP, even though some of the costs in the Plan are currently being recovered through base rates and the incremental cost of the Plan to customers will be less than shown above. For example, using the average of the certain actual storm hardening costs reflected in the company’s operation and maintenance expenses for 2017, 2018 and 2019 as a proxy, Tampa Electric estimates that the revenue requirement associated with amount of SPP O&M expenses currently being recovered through base rates is approximately $12.9 million.

# 9 Storm Protection Plan Alternatives and Considerations

Tampa Electric considered several "implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the plan" as required by Rule 25-6.030(3)(i).

The company started the development of the proposed SPP by briefly considering a "do nothing" scenario that would have resulted in no incremental investments in the transmission and distribution systems. This initial discussion was based upon on the company's historical performance and the current ongoing Storm Hardening Plan Initiatives. This alternative was good for level setting in that it identified the analyses that would be performed would need to examine the entire service area for opportunities for enhancement. In addition, this alternative was quickly dismissed as the statute is clear in that it requires all Florida investor owned utilities to submit a storm plan with the express purpose of hardening the system to reduce outage restoration costs and outage times. The statute emphasizes vegetation management, overhead hardening, and the undergrounding of overhead distribution lines, so the company began its planning with these activities at the forefront.

As described in the overview, the company engaged Accenture to evaluate several initiatives to enhance existing vegetation management plans and performance. As part of this analysis, several increments of activity and spending were evaluated. The company selected the option that yielded the most customer benefits.

Tampa Electric and 1898 & Co. used the resilience-based planning approach to establish an overall capital budget level and to identify and prioritize resilience investment in the company's T&D system. The budget optimization analysis was performed in $250 million increments up to $2.5 billion. The analysis showed 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. The company's overall investment level is right before the point of diminishing returns, which demonstrates that Tampa Electric's SPP has an appropriate level of investment over the 2020-2029 ten-year period capturing the Storm Protection Projects that provide the most value to customers.

In addition to the Programs included in the 2020-2029 SPP, Tampa Electric evaluated other capital Programs and Projects for inclusion in the Plan. Examples of things considered, but not included in this initial ten-year SPP are as follows:

- Undergrounding Distribution Feeders – The majority of customers are on laterals and analysis demonstrated higher cost-benefit to harden feeders and underground laterals.
- Upgrading wood distribution poles to non-wood materials – The company will continue to evaluate this option as manufacturing capabilities improve. At this time, the upgraded wood materials provide the best cost-benefit ratio for customers.
- Purchasing additional temporary access solutions such as increasing the number of mats – The solutions proposed in this Plan are more cost-effective and sustainable

As in the past with the company's prior Storm Hardening Plan Initiatives, Tampa Electric will also examine and analyze the processes and procedures used to implement the company's proposed 2020-2029 SPP Programs for any ongoing continuous improvement opportunities. This examination will assist in mitigating the resulting rate impact and ensure the benefits from the proposed SPP are realized.

# Tampa Electric's 2020–2029 Storm Protection Plan Appendices

# Appendix A

# Project Detail

# Distribution Lateral Undergrounding

## Tampa Electric's Distribution Lateral Undergrounding - Year 2020 Details

| Project ID | Circuit No. | Specific Project Detail | | Customers | | | | Priority Customers | Project Start Qtr | Construction | | Project Cost in 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | OH to UG Length Converted (miles) | Poles | Residential | Small C&I | Large C&I | Total | | | Start Qtr | End Qtr | |
| Lateral Hardening-Fuse-60588225 | 13174 | 0.29 | 15 | 374 | 34 | 1 | 409 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $125,235 |
| Lateral Hardening-Fuse-10786382 | 14040 | 0.23 | 13 | 98 | 6 | 2 | 106 | 10 | Q2 2020 | Q3 2020 | Q4 2020 | $150,431 |
| Lateral Hardening-Fuse-90755954 | 13454 | 0.30 | 23 | 292 | 21 | 1 | 314 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $238,629 |
| Lateral Hardening-Fuse-60451701 | 13174 | 0.24 | 14 | 301 | 11 | 2 | 314 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $230,114 |
| Lateral Hardening-Fuse-10933151 | 13897 | 0.79 | 33 | 64 | 20 | 1 | 85 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $221,051 |
| Lateral Hardening-Fuse-92421291 | 13972 | 0.44 | 23 | 379 | 6 | 1 | 386 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $248,973 |
| Lateral Hardening-Fuse-92881445 | 13710 | 0.45 | 32 | 158 | 17 | 0 | 175 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $401,397 |
| Lateral Hardening-Fuse-92599119 | 13390 | 0.72 | 46 | 266 | 27 | 3 | 296 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $750,732 |
| Lateral Hardening-Fuse-92407065 | 13815 | 0.38 | 15 | 12 | 3 | 1 | 16 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $68,399 |
| Lateral Hardening-Fuse-93019714 | 13840 | 0.13 | 9 | 39 | 2 | 0 | 41 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $51,112 |
| Lateral Hardening-Fuse-92634300 | 14032 | 0.31 | 21 | 306 | 10 | 2 | 318 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $390,745 |
| Lateral Hardening-Fuse-60287236 | 13509 | 0.15 | 14 | 144 | 14 | 0 | 158 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $175,078 |
| Lateral Hardening-Fuse-60182741 | 13312 | 0.15 | 15 | 52 | 11 | 7 | 70 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $101,387 |
| Lateral Hardening-Fuse-90241880 | 13972 | 0.90 | 49 | 130 | 7 | 6 | 143 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $687,129 |
| Lateral Hardening-Fuse-10643541 | 13390 | 1.17 | 67 | 221 | 22 | 2 | 245 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $1,095,650 |
| Lateral Hardening-Fuse-10786374 | 14040 | 0.27 | 16 | 205 | 13 | 0 | 218 | 11 | Q2 2020 | Q3 2020 | Q4 2020 | $334,434 |
| Lateral Hardening-Fuse-92829453 | 13961 | 0.34 | 25 | 447 | 3 | 2 | 452 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $292,496 |
| Lateral Hardening-Fuse-91406672 | 13836 | 0.35 | 25 | 91 | 6 | 0 | 97 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $248,786 |
| Lateral Hardening-Fuse-90288627 | 13815 | 0.88 | 32 | 51 | 9 | 0 | 60 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $423,948 |
| Lateral Hardening-Fuse-91432109 | 13071 | 0.14 | 15 | 20 | 5 | 0 | 25 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $163,279 |
| Lateral Hardening-Fuse-90738378 | 13071 | 0.16 | 20 | 296 | 35 | 0 | 331 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $145,327 |
| Lateral Hardening-Fuse-90911087 | 13724 | 0.54 | 32 | 31 | 4 | 0 | 35 | 6 | Q2 2020 | Q3 2020 | Q4 2020 | $423,395 |
| Lateral Hardening-Fuse-93026469 | 13815 | 0.49 | 15 | 27 | 2 | 0 | 29 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $375,085 |
| Lateral Hardening-Fuse-10629014 | 13146 | 0.54 | 30 | 91 | 6 | 0 | 97 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $608,468 |

# Appendix B

# Project Detail

# Transmission Asset Upgrades

| Tampa Electric's Transmission Asset Upgrades - Year 2020 Details | | | | | | |
|---|---|---|---|---|---|---|
| Project ID | Circuit No. | Pole Count | Project Start Month | Construction | | Project Cost in 2020 |
| | | | | Start Month | End Month | |
| Transmission Upgrades-69 kV-66654 | 66654 | 10 | May-20 | Jul-20 | Jul-20 | $317,000 |
| Transmission Upgrades-69 kV-66840 | 66840 | 34 | May-20 | Jul-20 | Aug-20 | $1,077,800 |
| Transmission Upgrades-69 kV-66007 | 66007 | 43 | Jun-20 | Aug-20 | Aug-20 | $1,363,100 |
| Transmission Upgrades-69 kV-66019 | 66019 | 21 | Jul-20 | Sep-20 | Oct-20 | $665,700 |
| Transmission Upgrades-69 kV-66425 | 66425 | 3 | Jul-20 | Oct-20 | Oct-20 | $95,100 |
| Transmission Upgrades-138/230 kV-230403 | 230403 | 5 | Jul-20 | Oct-20 | Oct-20 | $105,700 |
| Transmission Upgrades-69 kV-66413 | 66413 | 5 | Jul-20 | Oct-20 | Oct-20 | $158,500 |
| Transmission Upgrades-69 kV-66046 | 66046 | 30 | Jul-20 | Oct-20 | Nov-20 | $939,900 |
| Transmission Upgrades-69 kV-66059 | 66059 | 2 | Aug-20 | Nov-20 | Nov-20 | $63,400 |
| Transmission Upgrades-138/230 kV-230008 | 230008 | 59 | Aug-20 | Nov-20 | Jan-21 | $700,150 |
| Transmission Upgrades-138/230 kV-230010 | 230010 | 2 | Sep-20 | Jan-21 | Jan-21 | $900 |
| Transmission Upgrades-138/230 kV-230038 | 230038 | 1 | Oct-20 | Jan-21 | Jan-21 | $450 |
| Transmission Upgrades-138/230 kV-230003 | 230003 | 35 | Oct-20 | Jan-21 | Feb-21 | $15,750 |
| Transmission Upgrades-138/230 kV-230005 | 230005 | 24 | Oct-20 | Feb-21 | Feb-21 | $10,800 |
| Transmission Upgrades-138/230 kV-230004 | 230004 | 40 | Nov-20 | Feb-21 | Mar-21 | $18,000 |
| Transmission Upgrades-138/230 kV-230625 | 230625 | 12 | Nov-20 | Mar-21 | Mar-21 | $5,400 |
| Transmission Upgrades-138/230 kV-230021 | 230021 | 17 | Nov-20 | Mar-21 | Apr-21 | $7,650 |
| Transmission Upgrades-138/230 kV-230052 | 230052 | 9 | Dec-20 | Apr-21 | Apr-21 | $2,700 |
| Transmission Upgrades-69 kV-66024 | 66024 | 25 | Dec-20 | Apr-21 | Apr-21 | $27,750 |
| Transmission Upgrades-138/230 kV-230608 | 230608 | 18 | Dec-20 | May-21 | May-21 | $7,200 |
| Transmission Upgrades-138/230 kV-230603 | 230603 | 13 | Dec-20 | May-21 | May-21 | $1,800 |

The North American Electric Reliability Corporation ("NERC") defines the transmission system as lines operated at relatively high voltages varying from 69kV up to 765kV and capable of delivery large quantities of electricity. Tampa Electric's transmission system is made up of 69kV, 138kV and 230kV voltages and is designed to transmit power to the end-user 13.2kV distribution substations. As such, Tampa Electric does not attribute customer counts directly to individual transmission lines. It should be noted, that without Tampa Electric's transmission network in place, power could not be delivered to the distribution network which would result in automatic load loss.

# Appendix C

# Project Detail

# Substation Extreme Weather Hardening

# Reserved for Future Use

# Appendix D

# Project Detail

# Distribution Overhead Feeder Hardening

## Tampa Electric's Distribution Overhead Feeder Hardening - Year 2020 Details

| Project ID | Circuit No. | Specific Project Detail | Customers | | | | Priority Customers | Project Start Month | Construction | | Project Cost in 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Residential | Small C&I | Large C&I | Total | | | Start Month | End Month | |
| Distribution Feeder Hardening-Breaker-60067752 | 13308 | Tampa Electric will install (6) new reclosers, replace (3) existing manual switches with (3) reclosers, (45) fuses, (27) trip savers, and upgrade (52) feeder poles | 1,220 | 260 | 36 | 1,516 | 26 | May-20 | Aug-20 | Dec-20 | $1,153,700 |
| Distribution Feeder Hardening-Breaker-60095496-Recloser-92203202 | 13807 | Tampa Electric will install (8) new reclosers,(194) fuses, (40) trip savers, and upgrade (86) feeder poles | 1,159 | 103 | 16 | 1,278 | 12 | May-20 | Aug-20 | Dec-20 | $1,679,500 |
| Distribution Feeder Hardening-Breaker-60315127-Recloser-92189137 | 13805 | Tampa Electric will install (4) new reclosers, (202) fuses, (37) trip savers, and upgrade (93) feeder poles | 356 | 61 | 4 | 421 | 0 | May-20 | Aug-20 | Dec-20 | $1,565,900 |
| Distribution Feeder Hardening-Breaker-60066445 | 13745 | Tampa Electric will install (11) reclosers, (38) fuses, (10) trip savers, and upgrade (31) feeder poles | 3,106 | 242 | 50 | 3,398 | 62 | May-20 | Aug-20 | Dec-20 | $833,150 |
| Distribution Feeder Hardening-Breaker-60064337 | 13533 | Tampa Electric will install (13) reclosers, (42) fuses, (5) trip savers, upgraded breaker relays, and upgrade (33) feeder poles | 2,161 | 235 | 36 | 2,432 | 34 | May-20 | Aug-20 | Dec-20 | $1,044,300 |

# Appendix E

# Project Detail

# Transmission Access Enhancement

# Reserved for Future Use

# Appendix F

# 1898 & Co, Tampa Electric’s Storm Protection Plan Resilience Benefits Report

# 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 |

| **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 |

# 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:

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

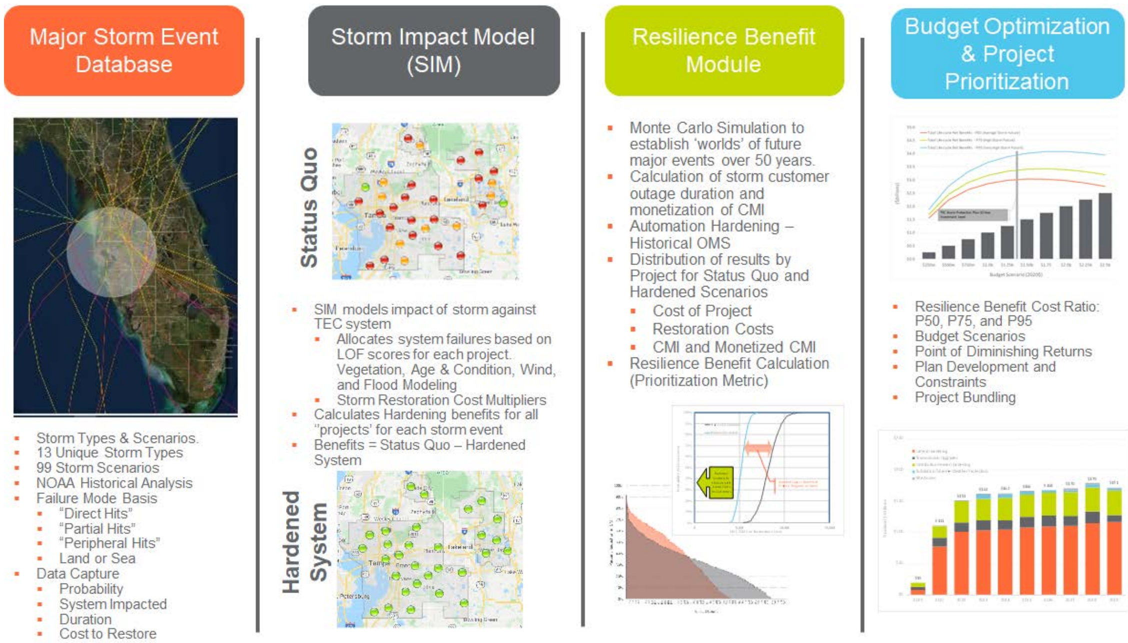
The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Replacements, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits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

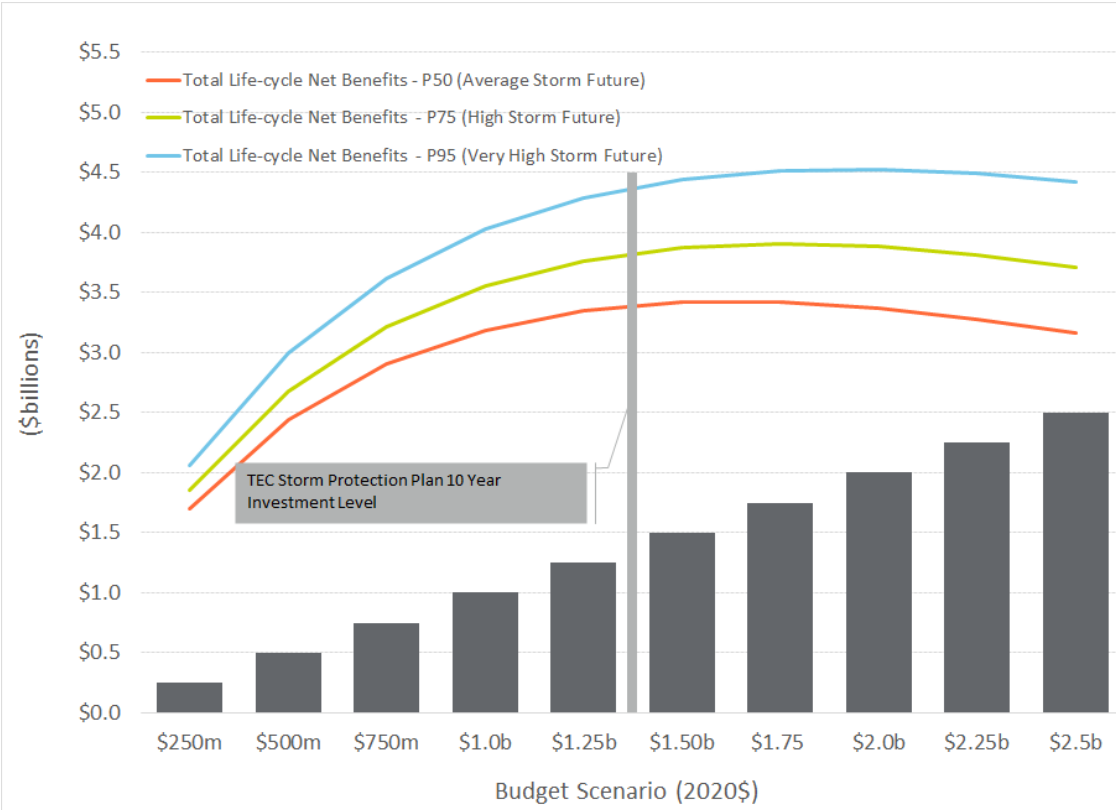
The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest resilience benefit cost ratio. It also performs a budget optimization over a range of budget levels to identify the point of diminishing returns.

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.

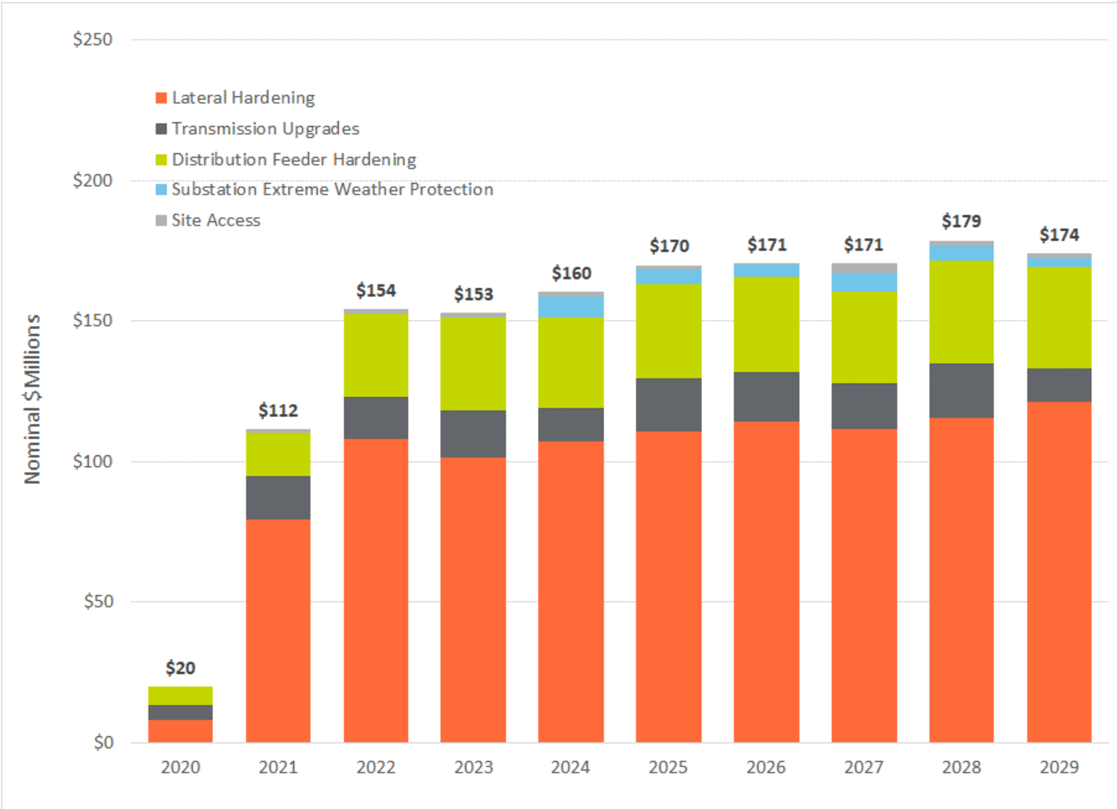
**Figure 1-2: Budget Optimization Results**




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**

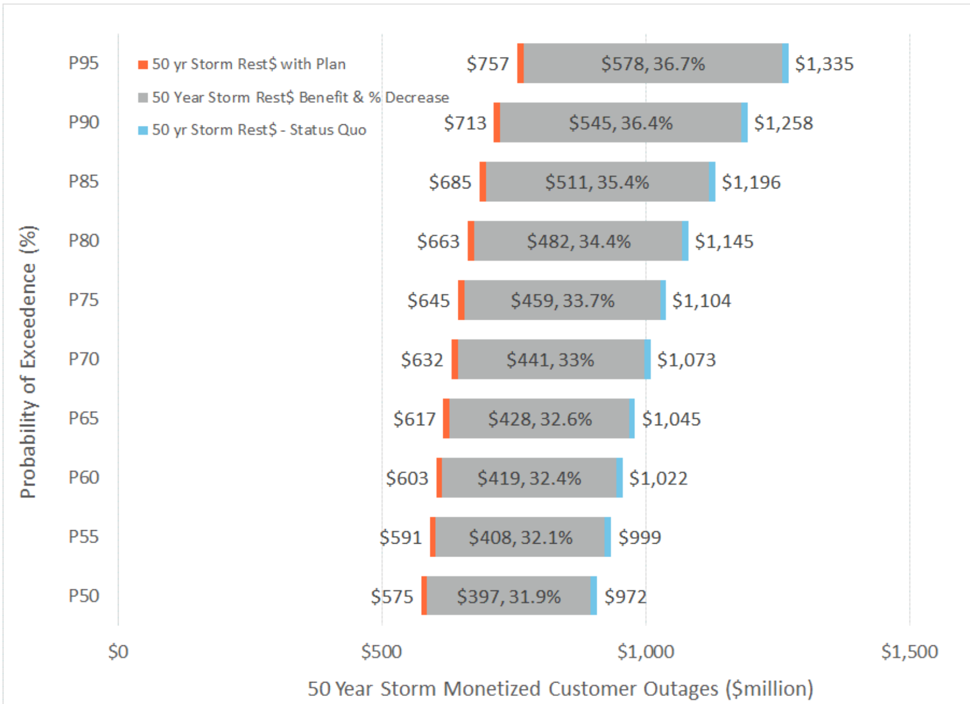



Customer benefits are calculated in terms of the:

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.

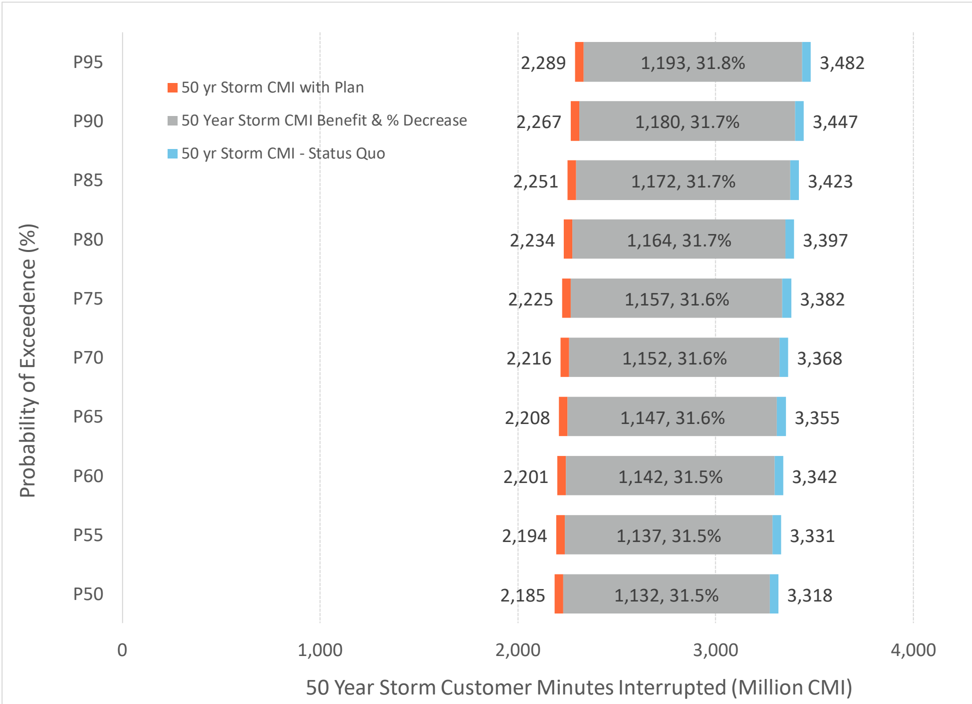
**Figure 1-4: Storm Protection Plan Restoration Cost Benefit**




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.

- 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.

# 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

- 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

> *"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.

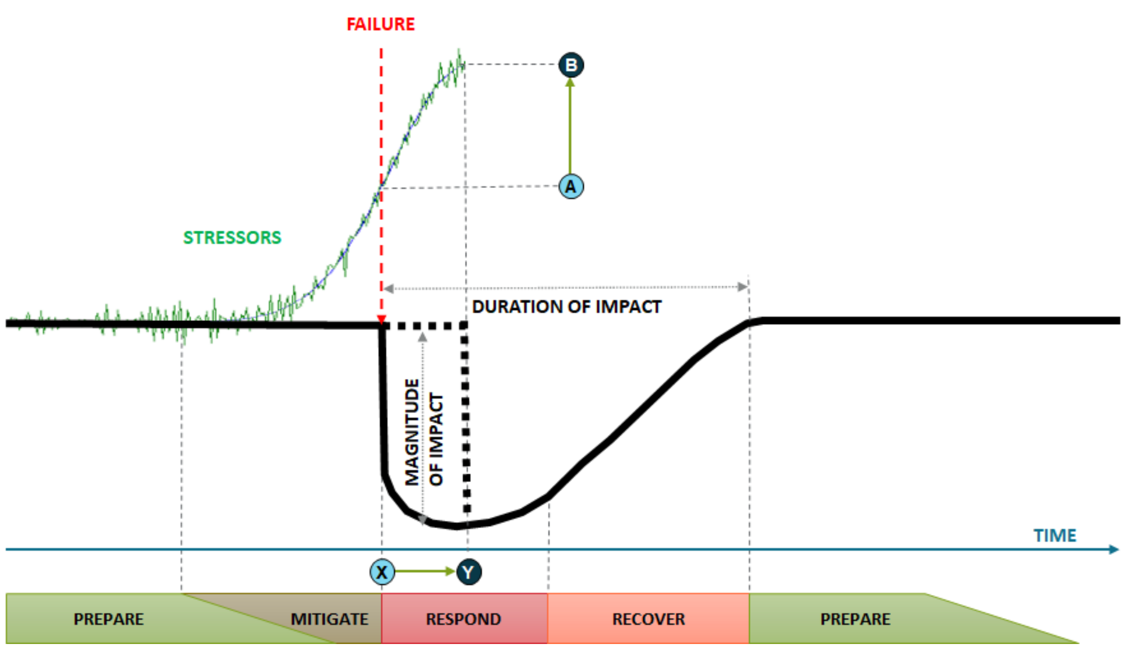
- Prepare (Before)
  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.
- Respond (During)
  The 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

(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.

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]** | **216** |
| **Site Access** | **[count]** | **96** |
| Roads | [count] | 70 |
| Bridges | [count] | 26 |

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.

### 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.

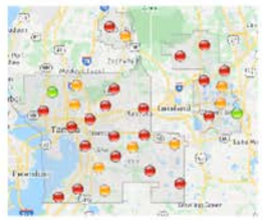
**Figure 2-2: Resilience Planning Approach Overview**

## 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

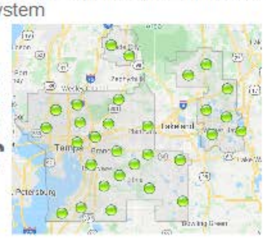
## Storm Impact Model (SIM)

Status Quo



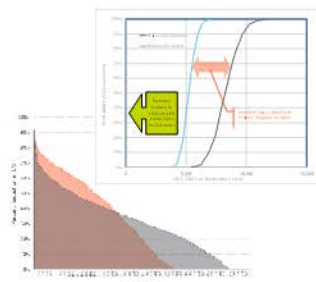
- SIM models impact of storm against TEC system
  - Allocates system failures based on LOF scores for each project. Vegetation, Age & Condition, Wind, and Flood Modeling
  - Storm Restoration Cost Multipliers
- Calculates Hardening benefits for all "projects' for each storm event
- Benefits = Status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

Hardened System

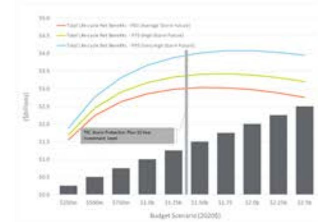


## Resilience Benefit Module

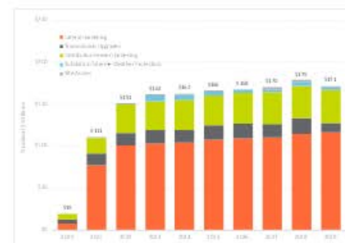
- Monte Carlo Simulation to establish 'worlds' of future major events over 50 years.
- Calculation of storm customer outage duration and monetization of CMI
- Automation Hardening – Historical OMS
- Distribution of results by Project for Status Quo and Hardened Scenarios
  - Cost of Project
  - Restoration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



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 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.

### 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.

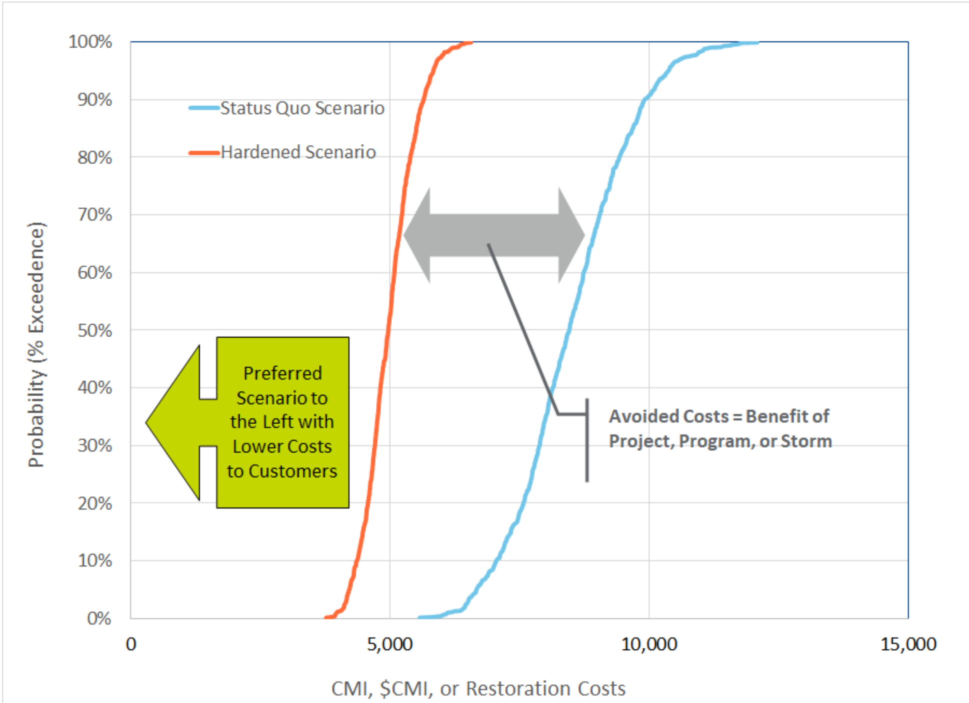
The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and 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**

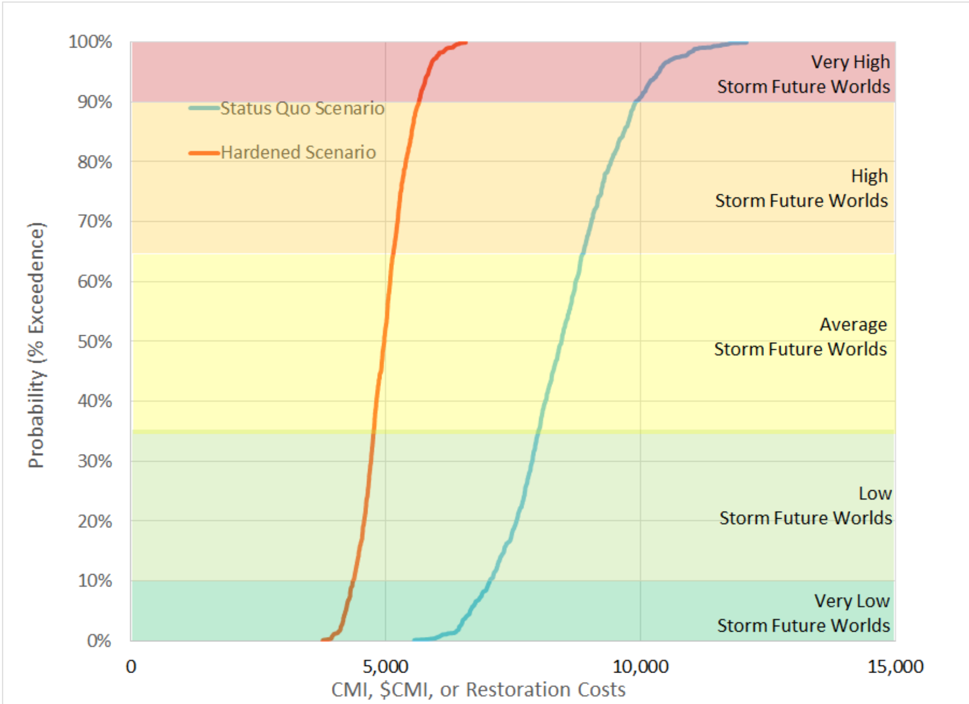



The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is 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.

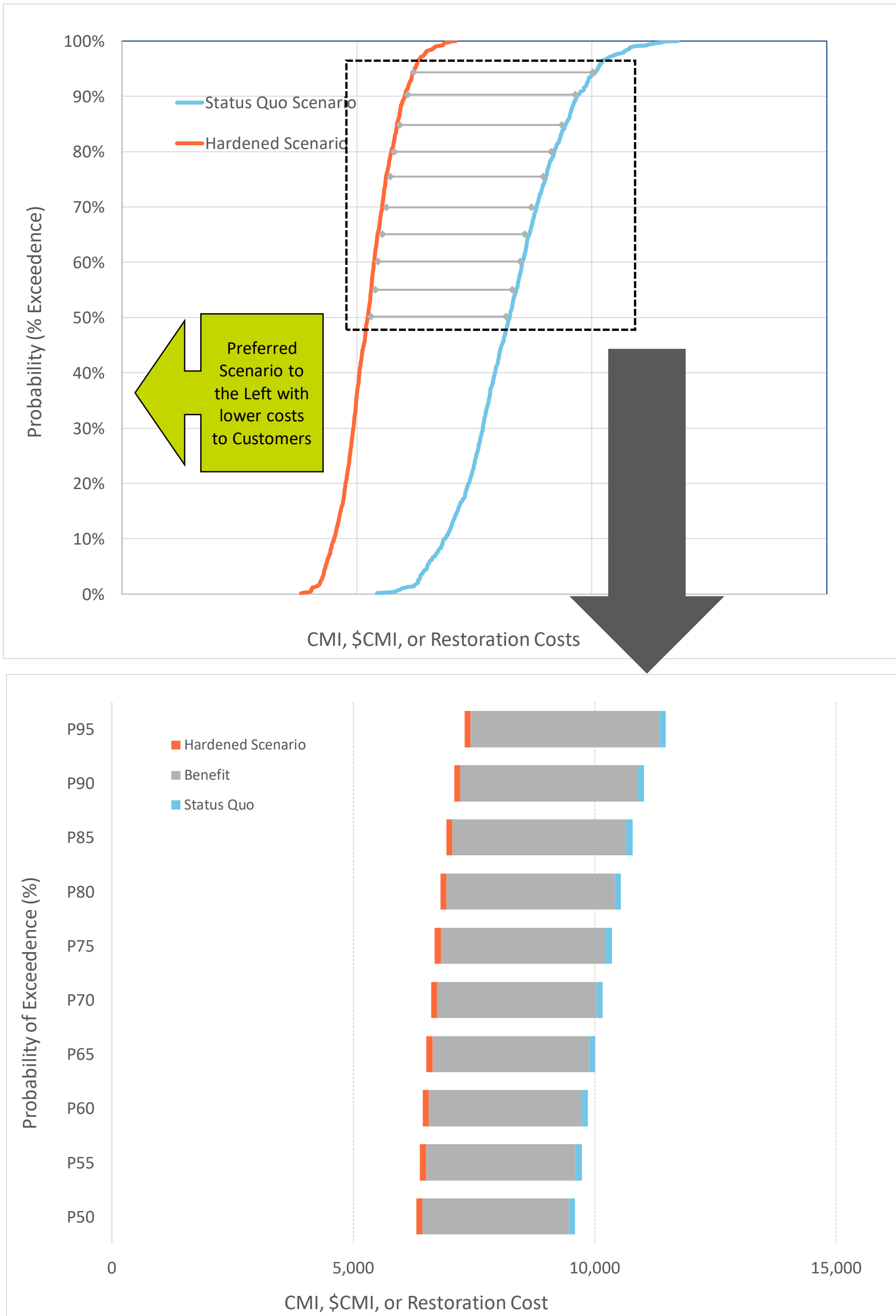
The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e. vertical) the less range in the result. The more horizontal the slope 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.

**Figure 2-5: S-Curves and Resilience Focus**



# 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:

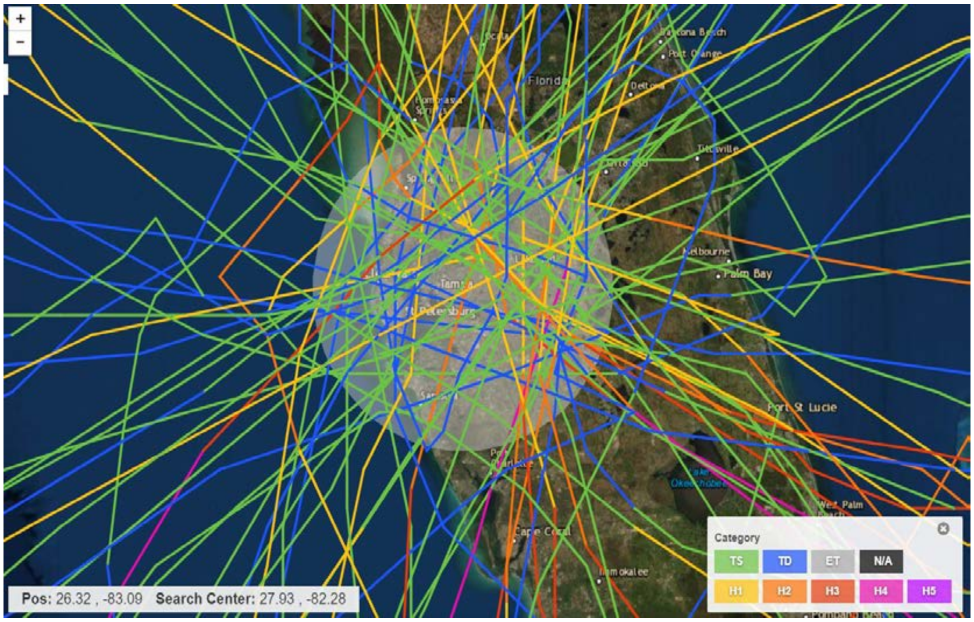
- Wind speeds of the storm (i.e. category of storm). Higher wind speeds means more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can 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 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]**

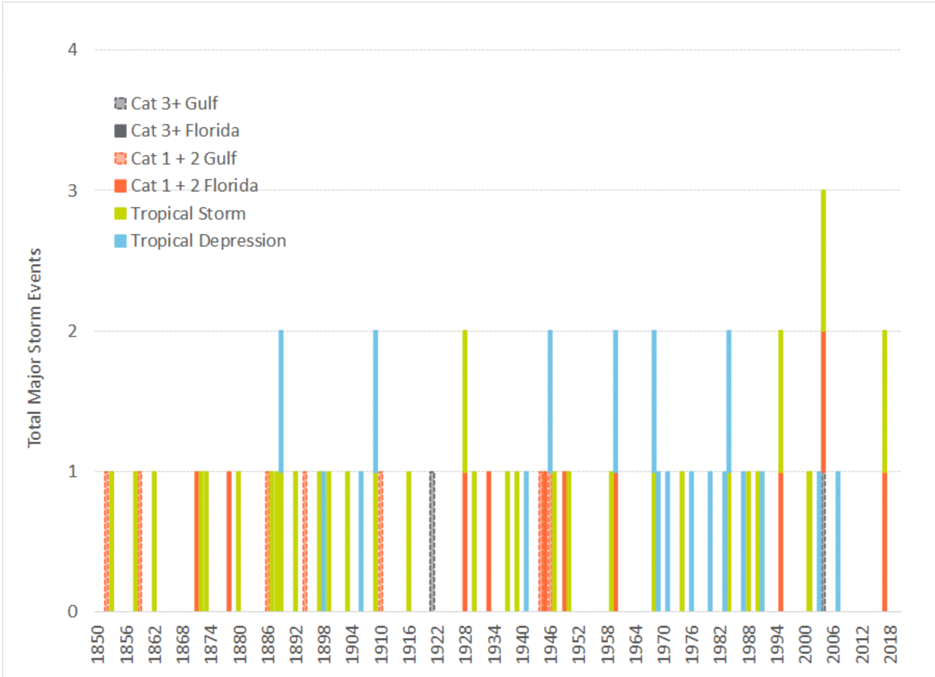



Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Direct Hits' over the time horizon. The figure shows a relative stability in the number of Category 1 and above storms over 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]**

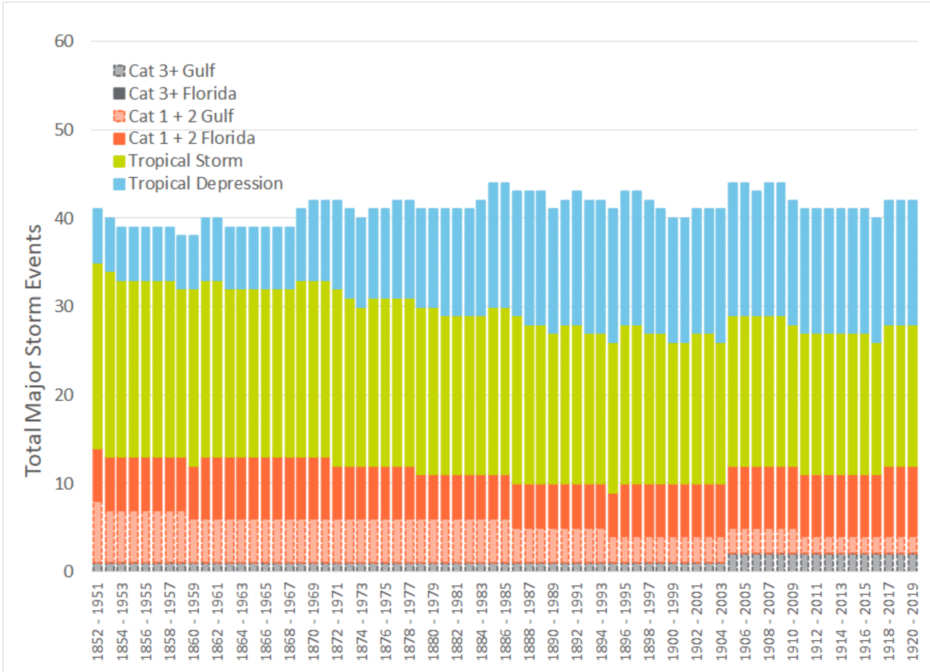
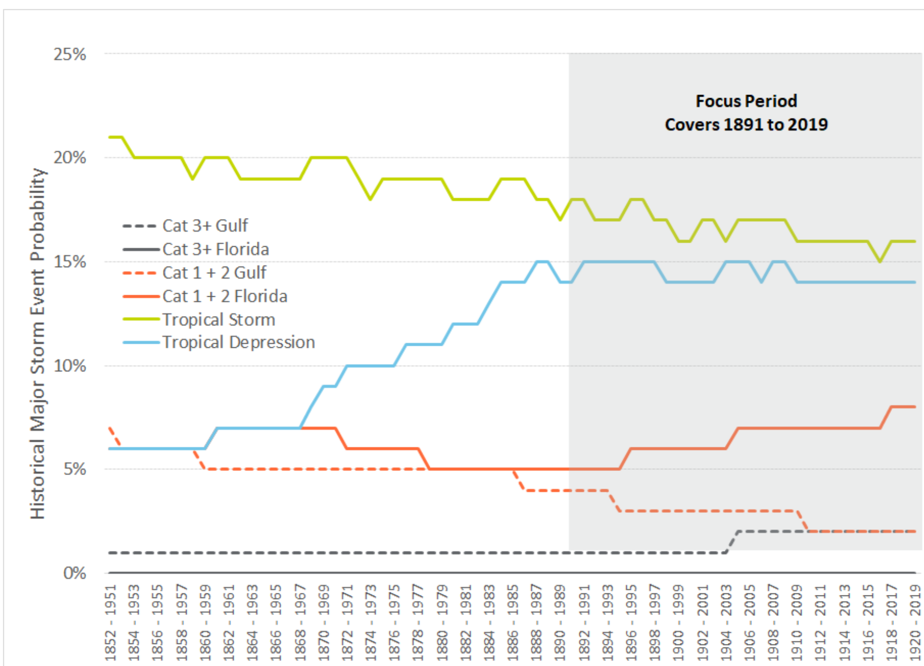



**Figure 3-4: "Direct Hits" (50 Miles) 100 Year Rolling Probability[3]**




[3] See Footnote 2

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]**

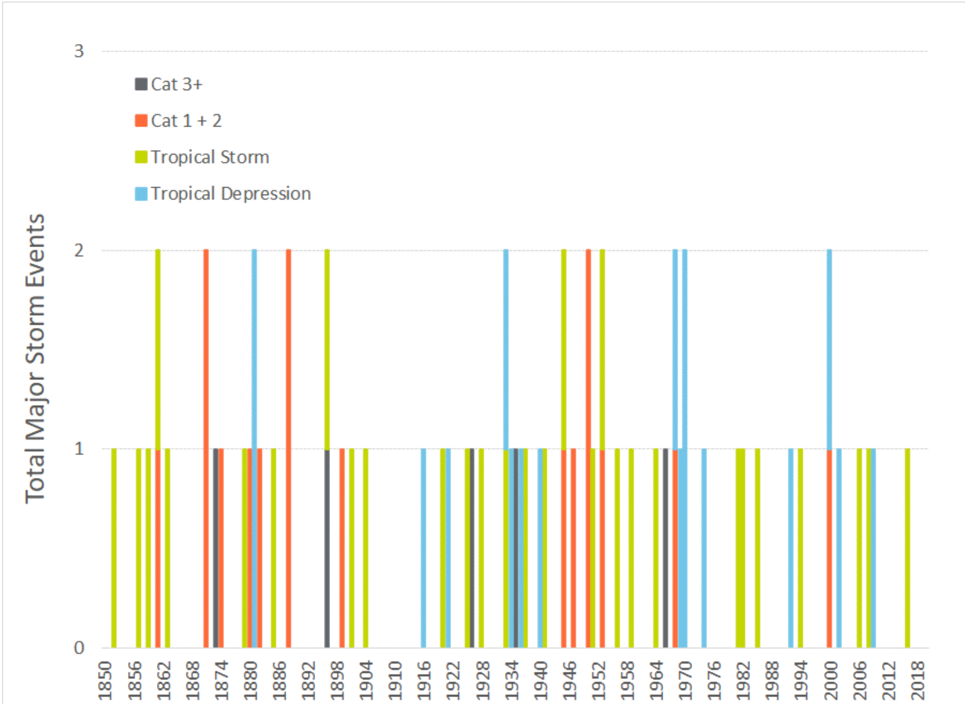



Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over 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]**

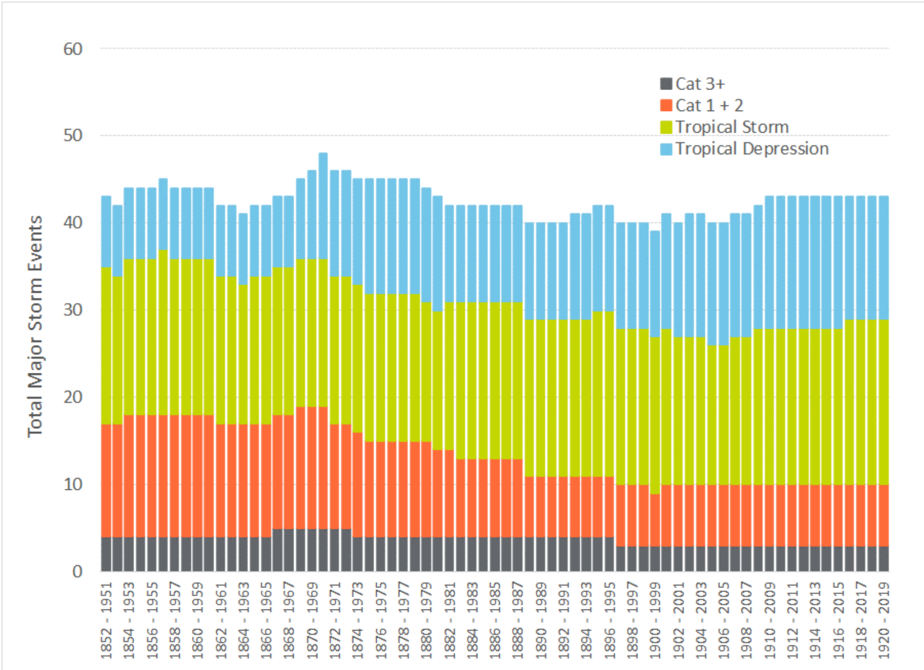
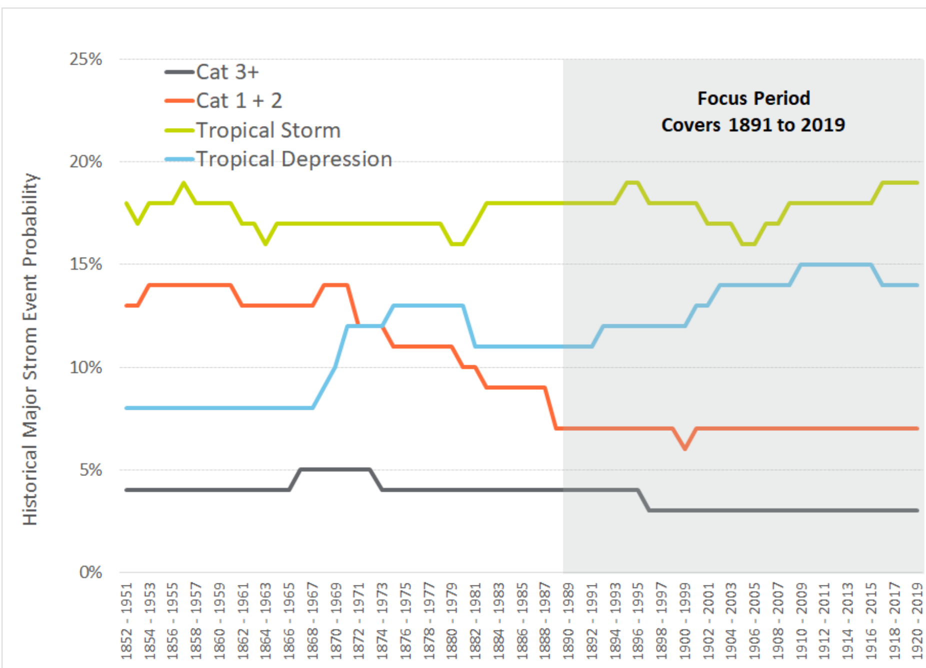



**Figure 3-7: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[5]**

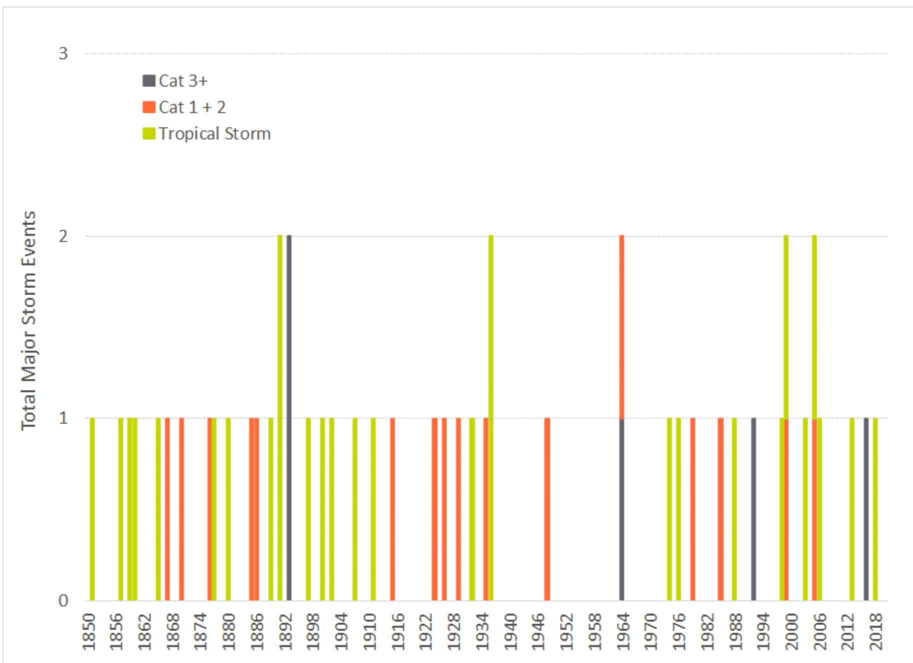



[5] See Footnote 2

### 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]**

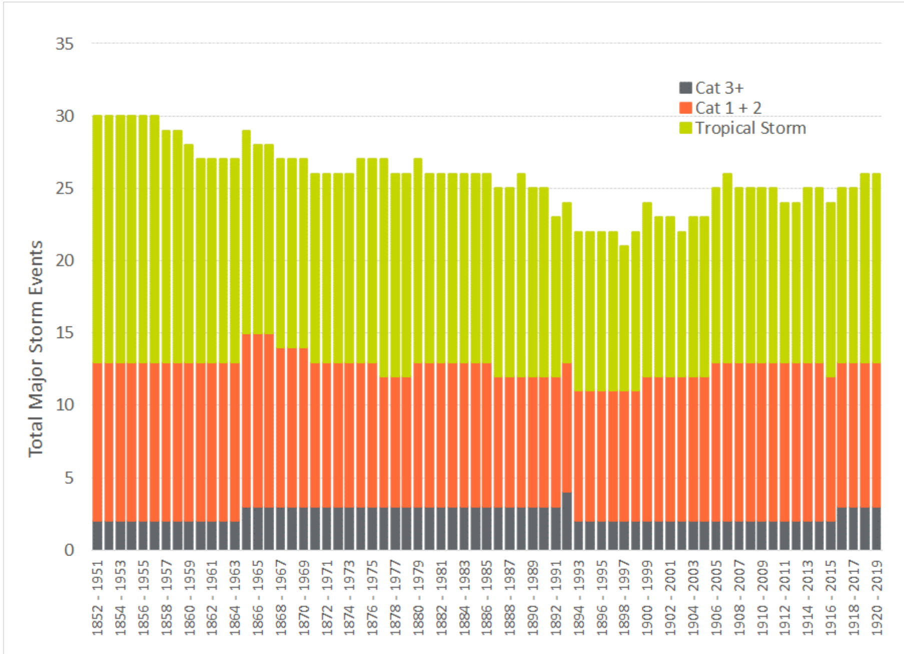
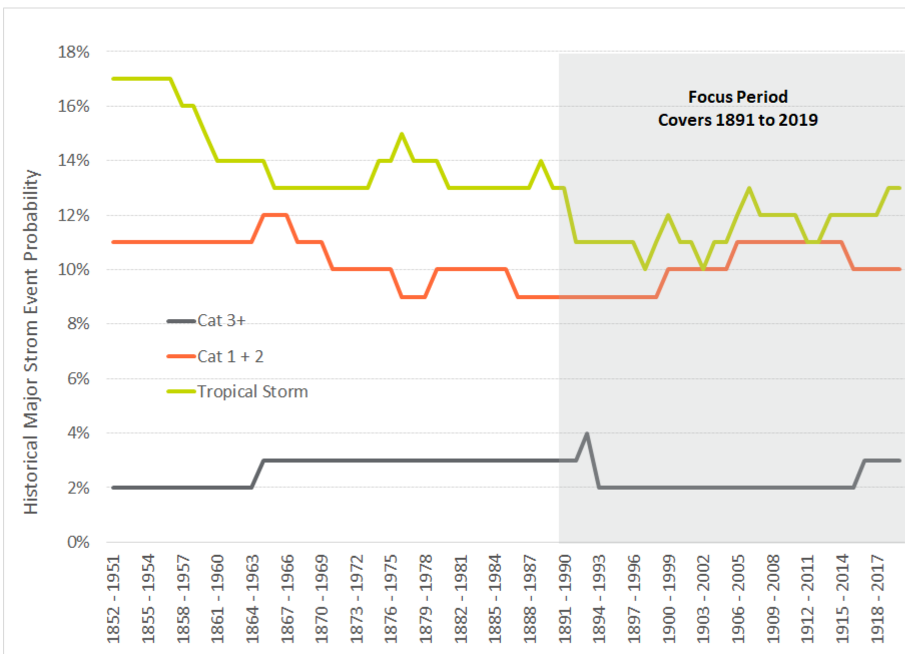



**Figure 3-10: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[7]**




[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**

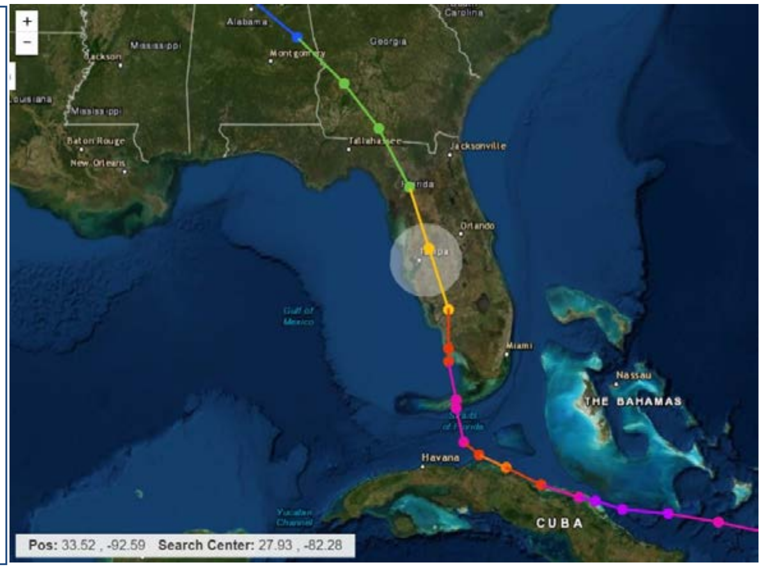



**Table 3-3: Storm Report Summary**

| 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 |

# 4.0 STORM IMPACT MODEL

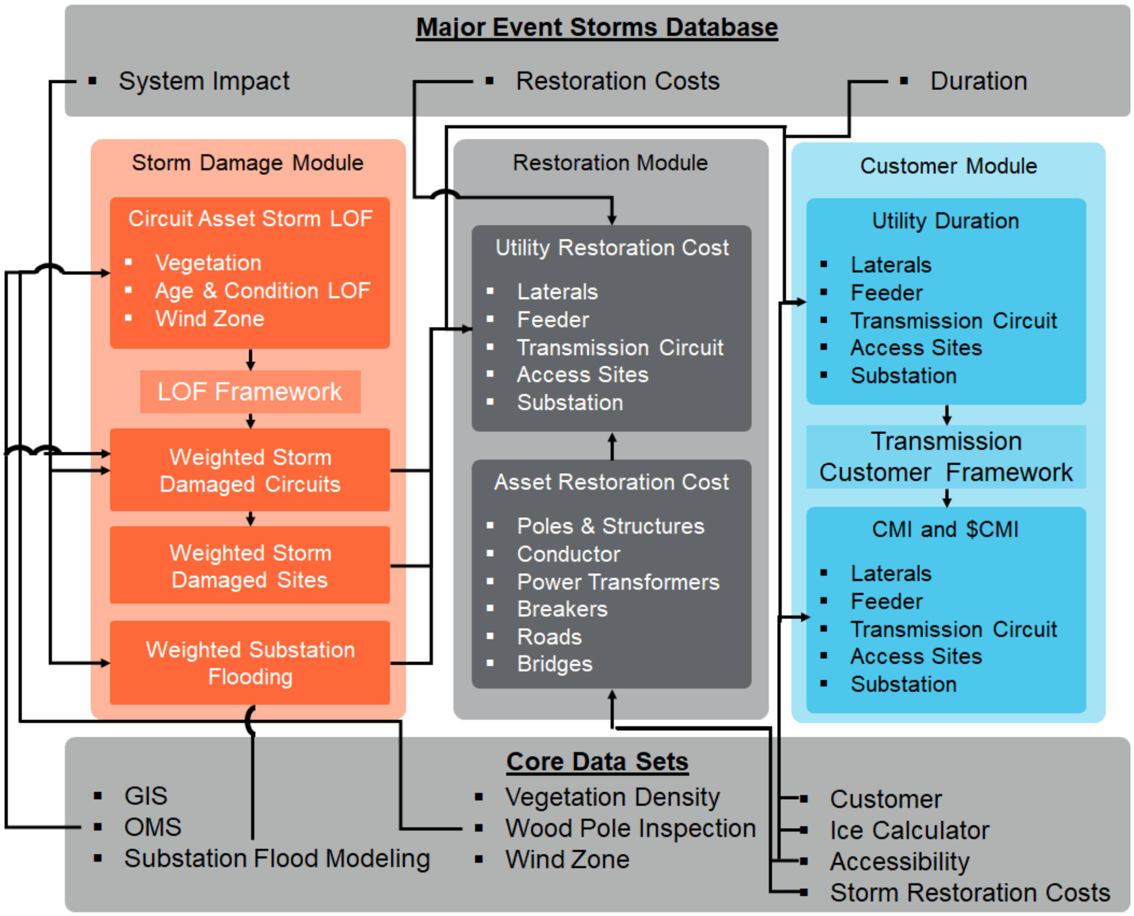
The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storms Event Database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for each storm stressor, the Storm Impact Model goes a layer deeper and develops the phases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

**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 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] | **216** |

**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.

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**

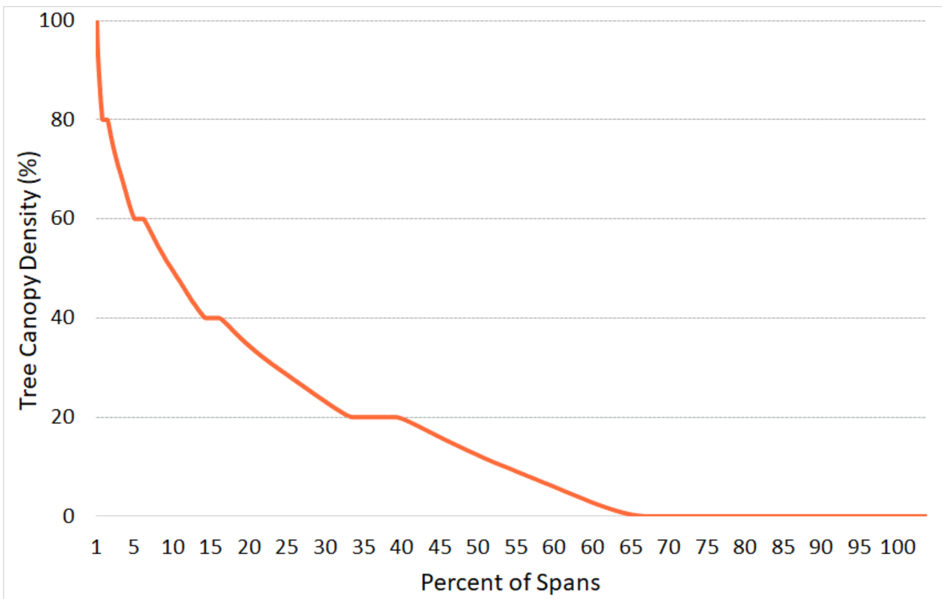
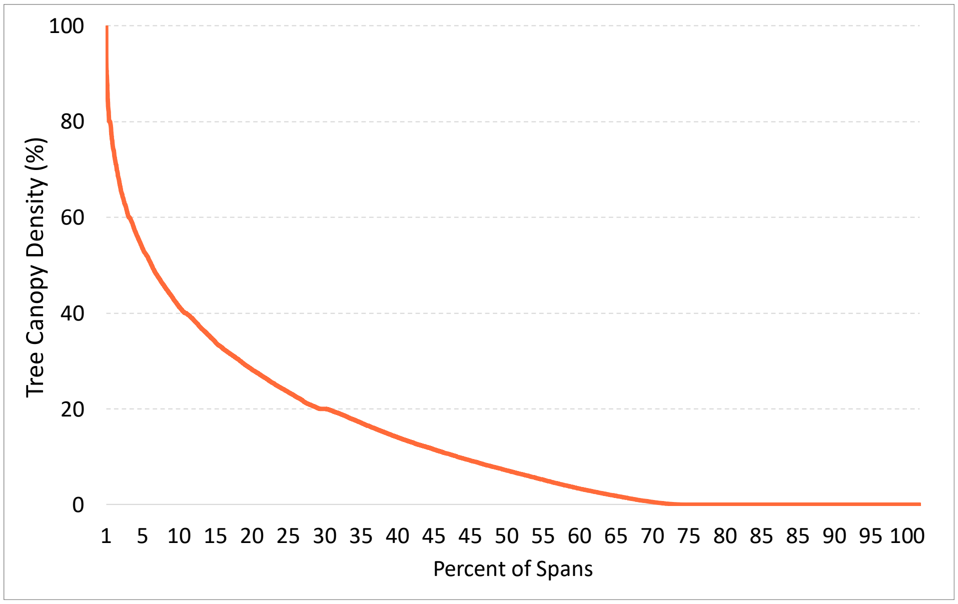


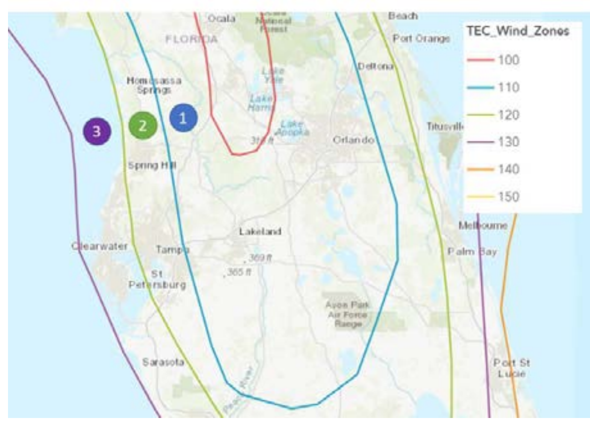
**Figure 4-3: Vegetation Density on TEC Transmission Conductor**




### 4.1.5 Wood Pole Inspection Data

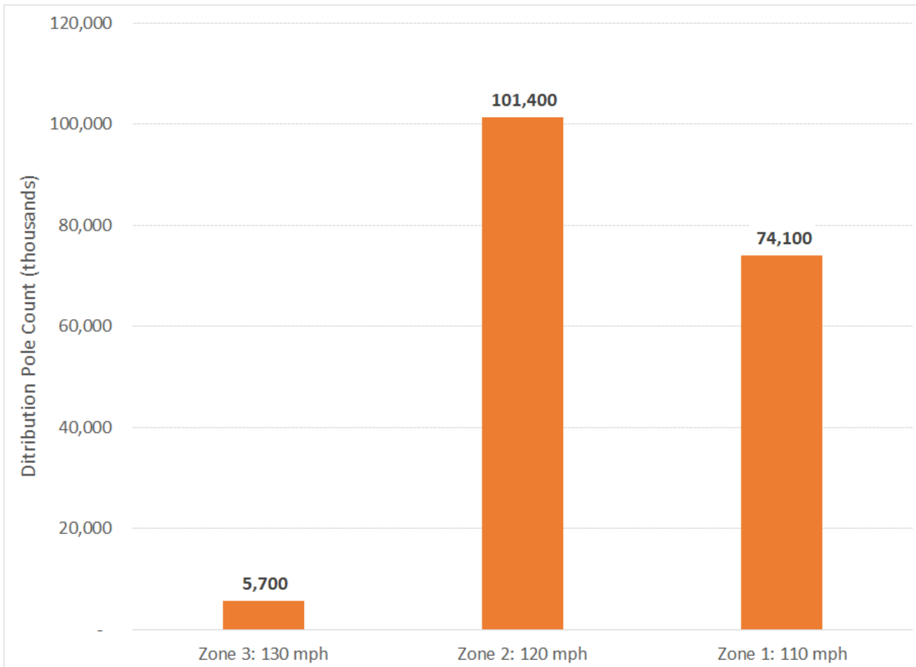
A compromised, or semi-comprised, pole will fail at lower dynamic load levels then poles with their original design strength. The Storm Impact Model utilizes wood pole inspection data within 1898 & Co.'s asset health algorithm to calculate an Asset Health Index (AHI) and 'effective' age for each pole.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

## 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.

### 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.

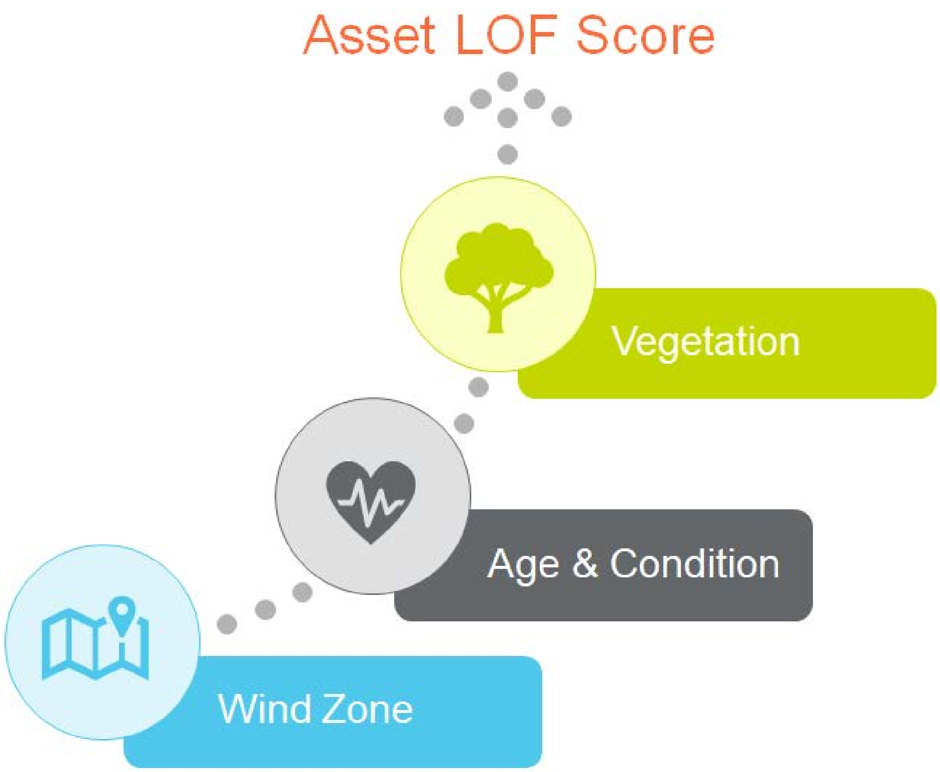
### 4.2.2 Circuits Storm Likelihood of Failure

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, 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.

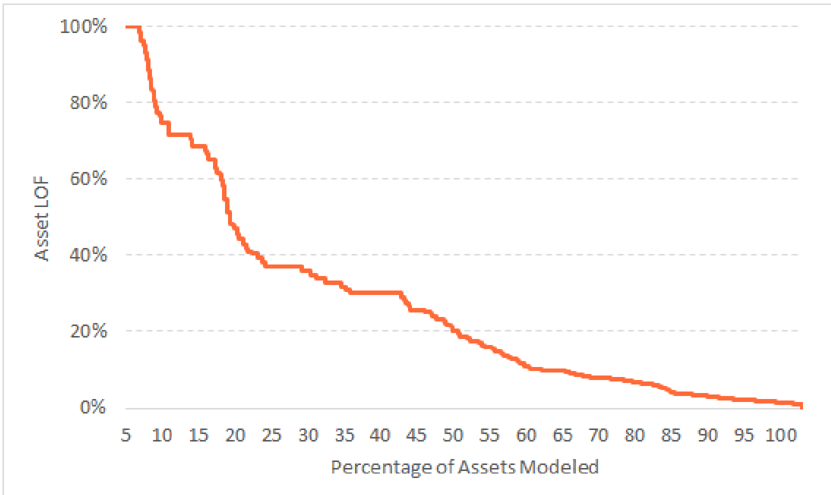
**Figure 4-5: Storm LOF Framework for Circuit Assets**




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

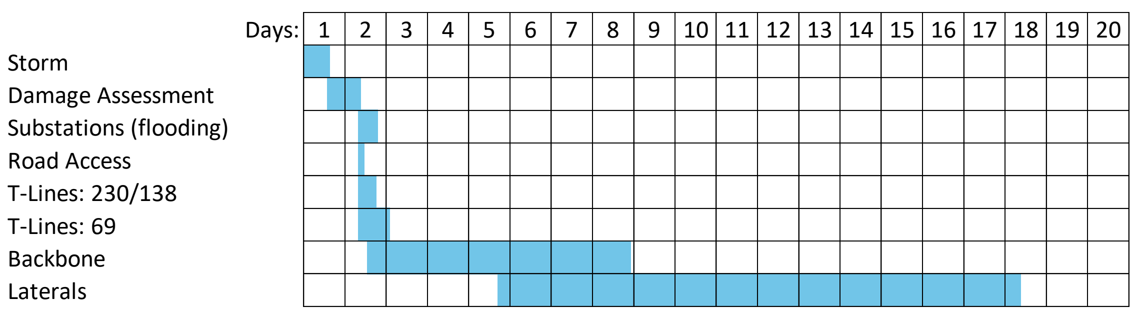
The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, 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 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.

### 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 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 |

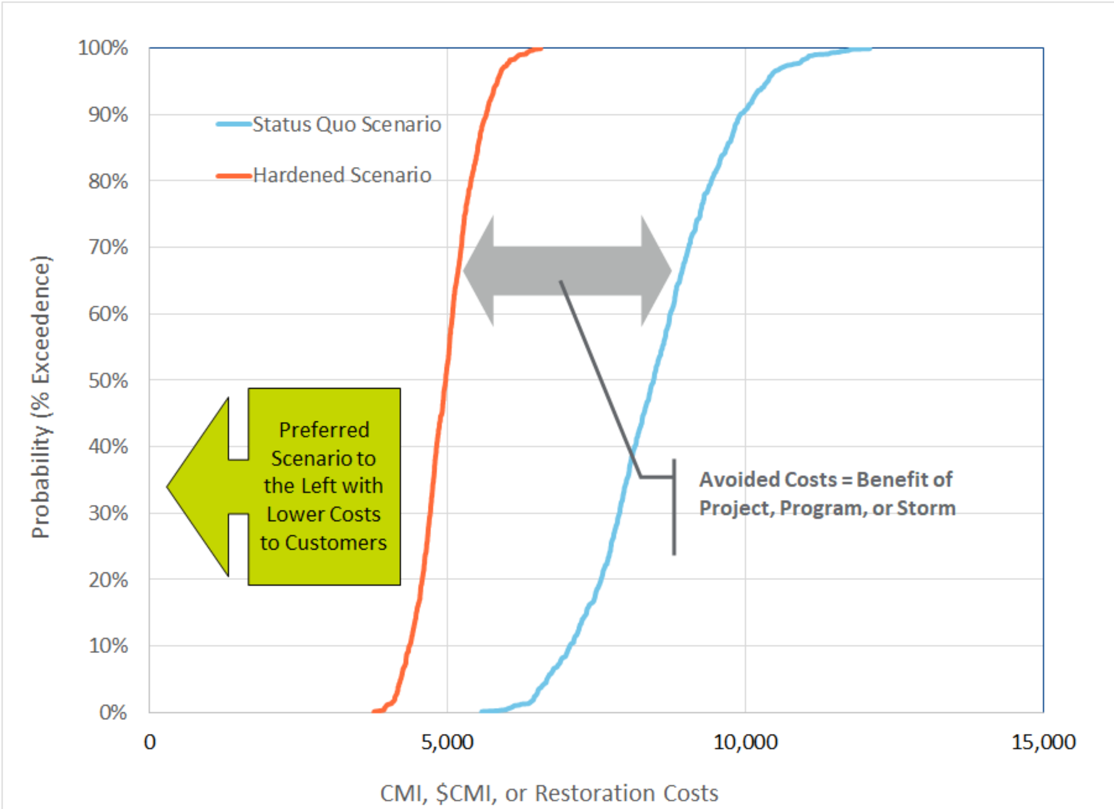
Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the 'Status Quo' and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and 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

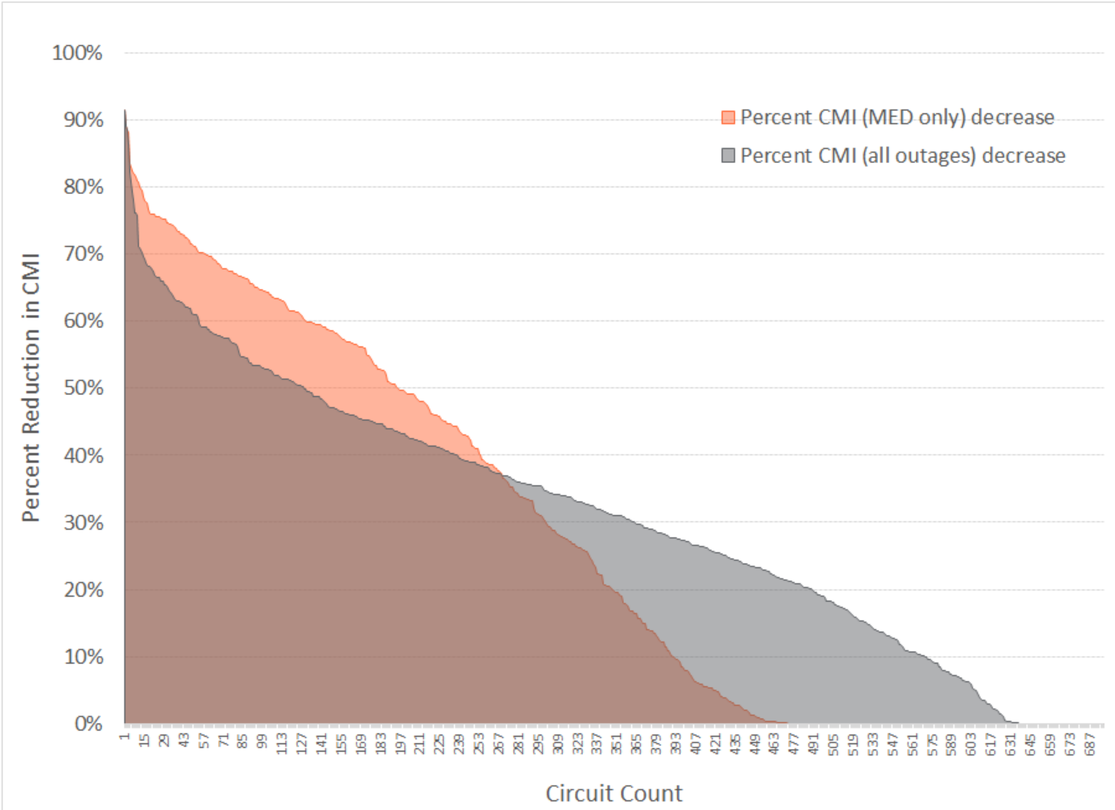
OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED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

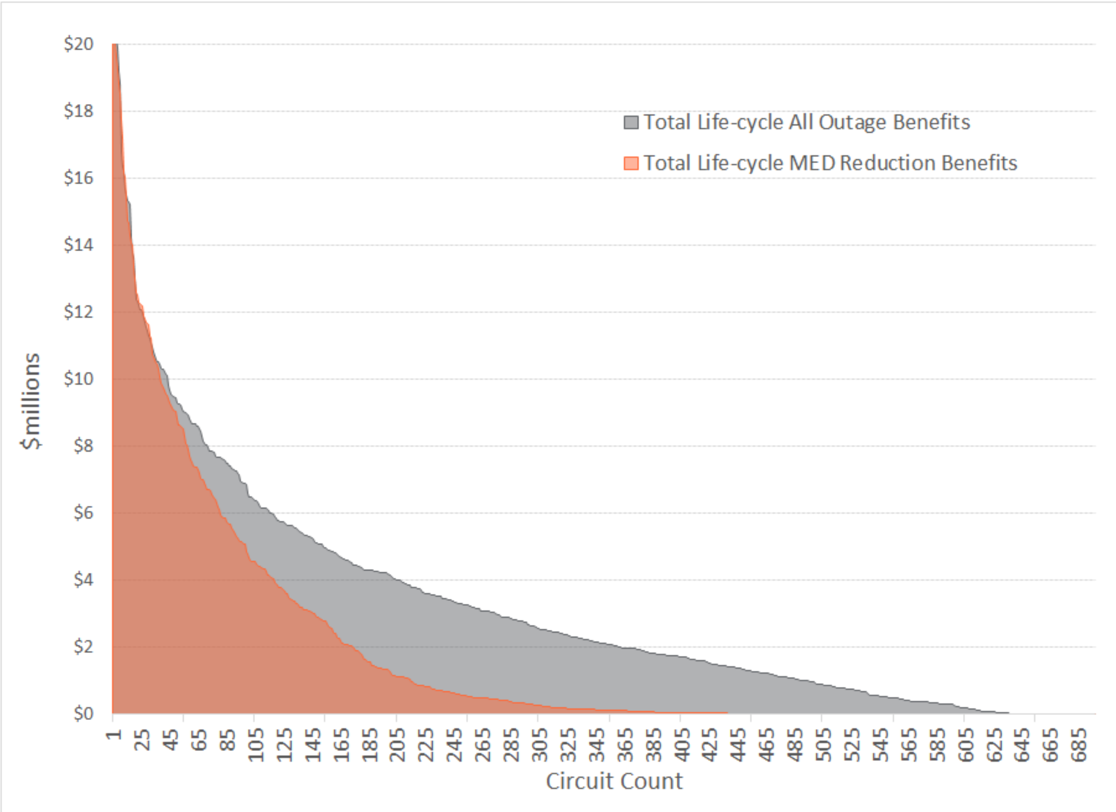
Figure 5-2 shows the percent decrease in CMI using this approach for all circuits. The figure is ranked from highest to lowest from left to right. The figure also includes the benefits to all outages. The figure shows a wide range of decreased CMI percentages with nearly 40 percent of circuits resulting 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**



# 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

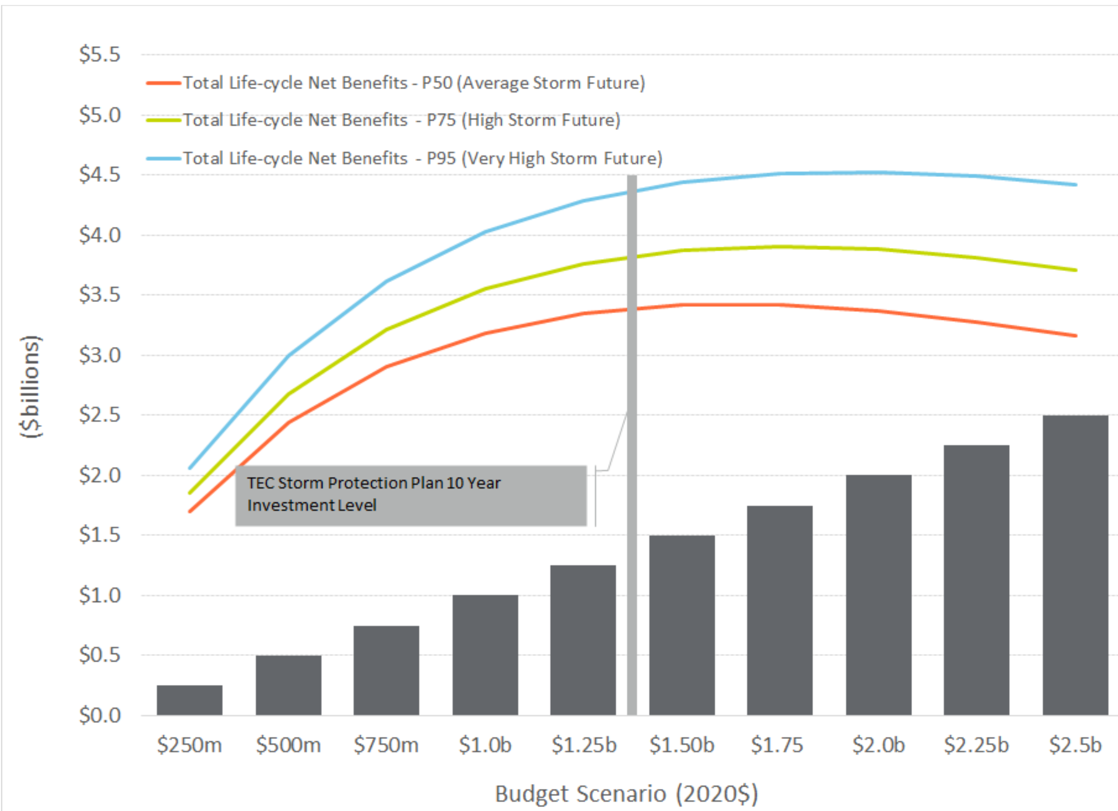
With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50 year NPV gross benefit value listed above. The ranking is performed for each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

# 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.

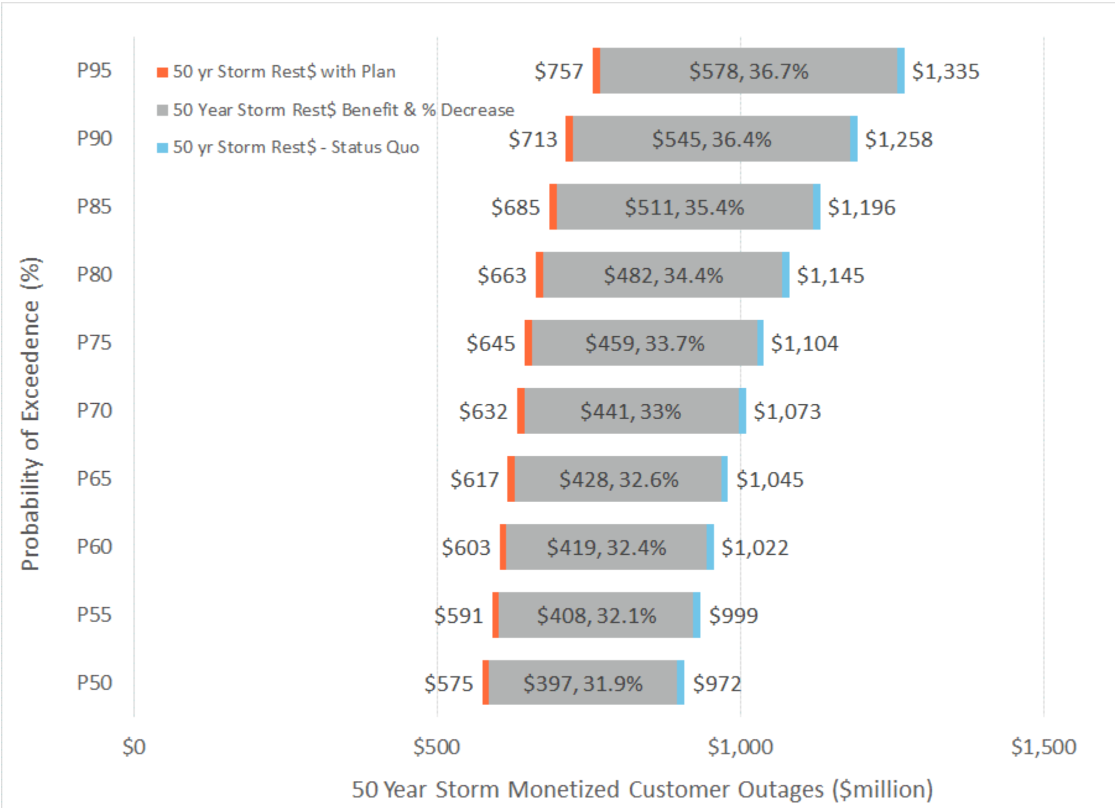
**Table 7-1: Storm Protection Plan Investment Profile by Program (Nominal $000)**

| 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**

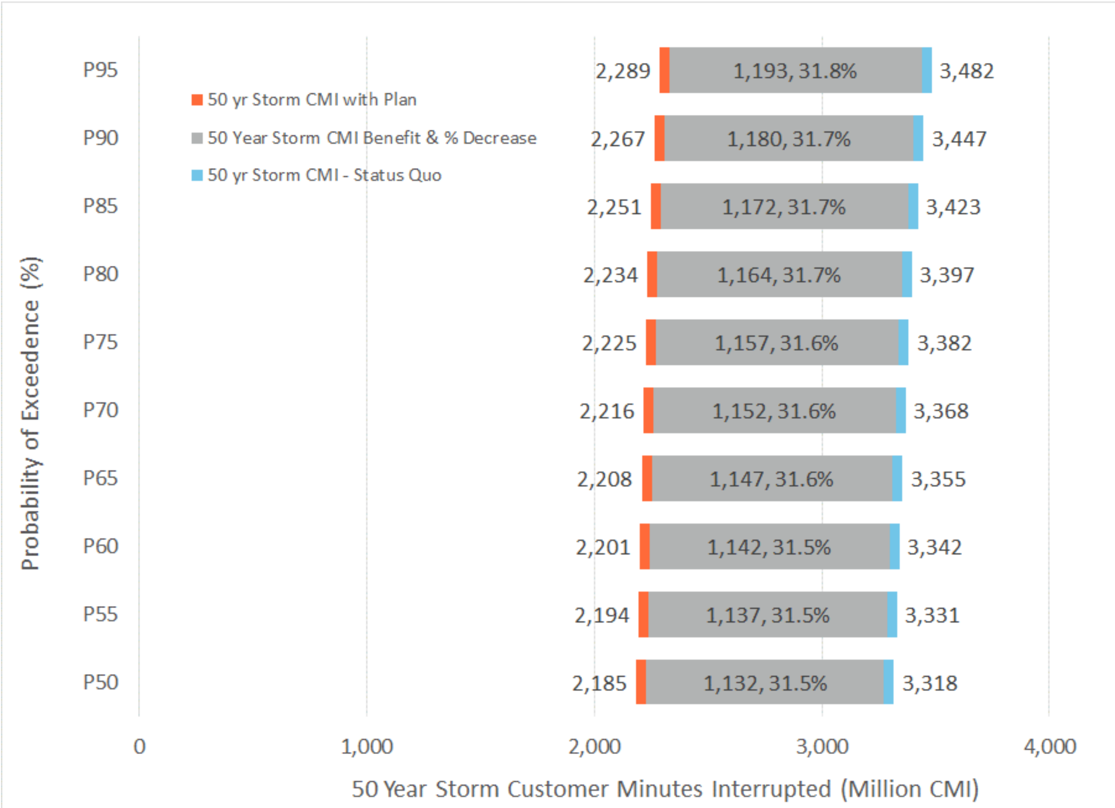



The figure shows that the 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to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

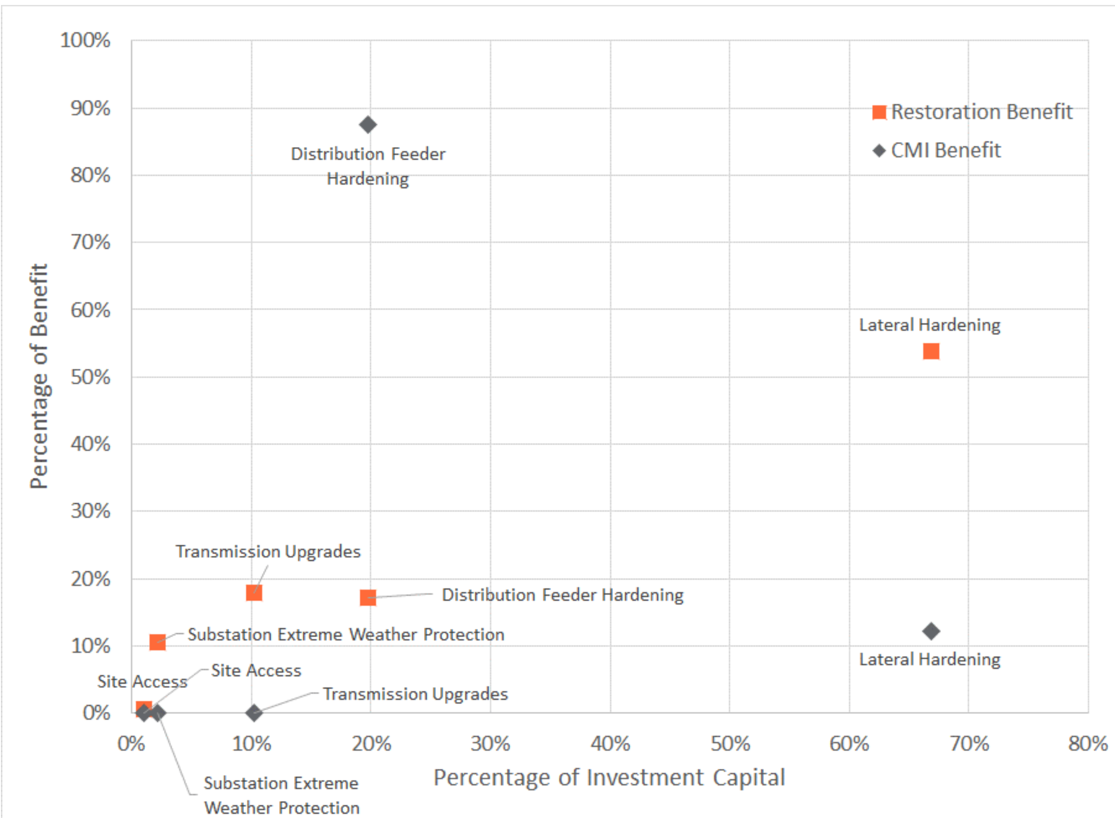



Table 7-7 and Figure 7-3 shows

- 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.

- 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.

- 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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# Appendix G

# Accenture, Tampa Electric’s Vegetation Management Storm Protection Program Analytic Support Report

# VEGETATION MANAGEMENT STORM PROTECTION PROGRAM ANALYTIC SUPPORT REPORT

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# 1 Executive Summary

In 2019, the Florida Legislature enacted a law stating that each investor-owned electric utility (utility) must file a Transmission and Distribution Storm Protection Plan (SPP) with the Florida Public Service Commission ("FPSC").[1] The SPP must cover the utility's immediate ten-year planning period. Each utility must file, for Commission approval, an updated Storm Protection Plan at least every three years.[2] The SPP must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability.[3] The FPSC later promulgated a rule to implement the SPP filing requirement.[4] This rule went into effect in February of 2020.

Since damage from wind-blown vegetation is a major cause of outages during extreme weather conditions, the rule requires utilities to provide, for each of the first three years of the SPP, a description of its proposed vegetation management activities including:

A. The projected frequency (trim cycle);
B. The projected miles of affected transmission and distribution overhead facilities;
C. The estimated annual labor and equipment costs for both utility and contractor personnel; and
D. A description of how the vegetation management activity will reduce outage times and restoration costs in extreme weather conditions.[5]

TECO is proposing a VM Storm Protection Program that includes three distribution vegetation management initiatives:[6]

1. Four-year distribution vegetation management cycle
2. Incremental initiative to augment annual distribution trimming by targeting supplemental miles each year:
    a. 400 miles in 2020
    b. 500 miles in 2021
    c. 700 miles in 2022 and beyond
3. Consolidate the gains of the baseline distribution cycle trim and supplemental trimming by introducing mid-cycle distribution vegetation inspections two years beyond each trim to prescribe additional distribution VM activities to:
    a. Ensure fast-growing species are kept in check until the next scheduled trimming.
    b. Remove troublesome species, hazard trees, and/or trees putting sensitive infrastructure at risk.

   The mid-cycle initiative will be phased in with the inspections applied to the feeder portion of circuits starting in 2021, rolling out to full circuits (feeder and lateral) starting in 2023.

Beyond the day-to-day and storm benefits, the distribution portion of the VM Storm Protection Program is planned to scale up over time, moving from today's complement of 196 field resources to a peak of 280 field resources across three years, and then settling into a steady-state number of approximately

[1] § 366.96(3), Fla. Stat.
[2] Document No 09233-2019 Filed on 10/7/2019 with the FPSC, 25-6.030 Storm Protection Plan, p. 1, lines 2-6
[3] § 366.96(3), Fla. Stat. 1
[44] *See* R. 25-6.030, F.A.C.
[5] Document No 09233-2019 Filed on 10/7/2019 with the FPSC, 25-6.030 Storm Protection Plan, p. 3, lines 10-17
[6] The Vegetation Management Program also includes the baseline transmission trim cycles as well an incremental transmission vegetation management initiative, but those activities are outside of the scope of this report.

270 field resources. The phased rollout and associated resource load and budget are outlined in Table 1-1, below:

**Table 1-1: Recommended Approach**

| | Baseline 4-Year Cycle | Supplemental Miles | Feeder Mid-Cycle | Lateral Mid-Cycle | Estimated Resource Load[7] | Budget[8] |
|---|---|---|---|---|---|---|
| 2020 | Yes | 400 | Pilot 1-5 Circuits | None | 228 | $17.1M |
| 2021 | Yes | 500 | Inspect 60 Miles | None | 257 | $20.0M |
| 2022 | Yes | 700 | Inspect 48 Miles | Pilot 1-5 Circuits | 262 | $21.4M |
| 2023 | Yes | 700 | Inspect 46 Miles | Inspect 208 Miles | 280 | $24.0M |
| 2024 | Yes | 700 | Inspect 45 Miles | Inspect 177 Miles | 270 | $24.3M |
| 2025 | Yes | 700 | Inspect 96 Miles | Inspect 156 Miles | 270 | $25.5M |
| 2026 | Yes | 700 | Inspect 60 Miles | Inspect 150 Miles | 270 | $26.8M |
| 2027 | Yes | 700 | Inspect 45 Miles | Inspect 198 Miles | 270 | $28.1M |
| 2028 | Yes | 700 | Inspect 52 Miles | Inspect 155 Miles | 270 | $29.5M |
| 2029 | Yes | 700 | Inspect 54 Miles | Inspect 186 Miles | 270 | $31.0M |

These initiatives are projected to reduce day-to-day vegetation-caused customer interruptions by 21 percent and storm-related vegetation-caused outages by 29 percent relative to carrying out the 4-Year Trimming Cycle alone.

[7] Resource projections from 2023 forward fluctuate with the specific blend of circuits that come up for mid-cycle trimming each year. 270 represents the average for these years, and TECO will manage the mid-cycle scope to match budget.
[8] Budget reflects anticipated vegetation management costs for 1) the baseline 4-year cycle trim, 2) supplemental trim miles, 3) mid-cycle activities and 4) corrective maintenance. Excluded are the anticipated company-wide restoration costs associated with day-to-day outages and major storm events

## 2 Overview

TECO engages in 4-year distribution cycle trimming activities on an ongoing basis, working approximately one quarter of their overhead distribution system mileage every year. The goal is to trim tree limbs such that it will take four years before they can grow sufficiently to encroach on the clearances established for their lines. At various locations in the system, certain fast-growing tree species and/or right-of-way constraints on trimming result in isolated patches that may require attention between scheduled cycle trims. This often takes the form of Corrective Maintenance, where a crew is called out to address an impending issue on a specific tree because its limbs have grown too close to the line or because a tree, aided by the elements, makes contact with the lines and triggers an outage.

TECO continuously analyzes its vegetation management program using some of the industry's leading analytic tools. One of these tools is the Tree Trimming Model (TTM), originally developed by Davies Consulting (acquired by Accenture in 2017). Since the initial implementation of the model in 2006, TECO has continued to refine its program and update the tool's configuration using its growing set of historical spending and reliability performance data.

The TTM employs an analysis of day-to-day outages caused by vegetation, as well as a sampling of outages with unknown and weather cause codes which might be attributable to vegetation. TTM considers such outages in the context of the amount of time that has elapsed since the last time the trees on that circuit were trimmed. Universally, the analysis shows that outage volumes rise as a function of time since last trim, but the degree to which outages and their reliability impact escalate vary as a result of factors such as tree density, tree species, voltage, customer density, microclimate and a variety of others. In the configuration stages of the TTM modeling, circuits are grouped according to their similarity in terms of outage escalation and grouped separately as a function of how expensive it is to trim them, yielding a matrix of combinations of reliability and cost groupings. These expressions of cost and reliability, as a function of time, drive a ten-year prioritization aimed at getting the best day-to-day performance per dollar spent on trimming activities.

During extreme weather conditions, the proximity of limbs to lines and the cross-sectional area of vegetation upon which winds can exert force (referred to herein as the 'sail area') play a large factor in the degree of damage the electrical system will sustain due to vegetation-caused outages. Because the time elapsed since last trim is a direct driver of vegetation to conductor clearances when a storm arrives, the relationship between years since last trim, wind speed, and the extent of damage sustained has been studied and built into TTM's Storm Module. Using the trim list outputs of the TTM and an array of probable windspeeds for the Tampa area, the Storm Module predicts damage levels and associated restoration costs for typical years and can also project the impact of storms of specified magnitude.

Both TTM and the Storm Module address the effects of trimming circuits in their entirety, but some of TECO's proposed Vegetation Management initiatives are more targeted and address only portions of circuits in any given year. To accommodate this, Accenture crafted an Enhanced Storm Module for TTM to estimate the value derived from these targeted initiatives which change the state of only part of any given circuit at a time.

# 3 Approach

TECO used TTM and its storm modules to establish a set of baseline performance metrics associated with its four-year cycle, and then evaluated supplemental activities against that baseline:

- Supplemental trimming scenarios in which TECO targeted and trimmed an additional 100, 300, 500, 700 or 900 miles per year, and
- Mid-cycle activities whereupon circuits (either the feeder or the complete circuit) are inspected two years after their most recent trim, and follow-up vegetation management activities are prescribed to enhance both the day-to-day and extreme weather condition performance of the system.

The effects of the supplemental trimming and mid-cycle initiatives build upon the base of the 4-year trimming cycle. For consistency of presentation throughout the document, all three are referred to herein as initiatives:

**Table 3-1: Initiative Approach**

| Initiative | Name |
|---|---|
| 1 | Baseline 4-year Trimming Cycle |
| 2 | Supplemental Trimming |
| 3 | Mid-cycle Inspection & VM Activities |

The effects of these initiatives are cumulative, in that any version of Initiative 2 requires that the baseline 4-year cycle to be in effect, and Initiative 3 would not be implemented without the baseline trim cycle and Initiative 2 in place.  There are many different combinations of activities, any of which could serve as the company’s VM program. The benefits of each possible activity can only be evaluated by comparing the benefits of different programs, or combinations of activities. Consequently, the team created different possible VM programs, each with a different set of component activities. The programs which appear in this document consist of component activities as follows:

**Table 3-2: Program Nomenclature and Initiative Components**

| Program Name | Initiative 1 Component | Initiative 2 Component | Initiative 3 Component |
|---|---|---|---|
| **Program 1** | 4-year cycle trim | n/a | n/a |
| **Program 2 – 100** | 4-year cycle trim | 100 Supplemental Miles | n/a |
| **Program 2 – 300** | 4-year cycle trim | 300 Supplemental Miles | n/a |
| **Program 2 – 500** | 4-year cycle trim | 500 Supplemental Miles | n/a |
| **Program 2 – 700** | 4-year cycle trim | 700 Supplemental Miles | n/a |
| **Program 2 – 900** | 4-year cycle trim | 900 Supplemental Miles | n/a |
| **Program 3a – 700** | 4-year cycle trim | 700 Supplemental Miles | Mid-cycle on feeders only |
| **Program 3b – 700** | 4-year cycle trim | 700 Supplemental Miles | Mid-cycle on whole circuits |
| **Program 2 – 457** | 4-year cycle trim | Phased approach – 400 Supplemental Miles in 2020, 500 in 2021 and 700 in 2022 and beyond | n/a |
| **Program 3ab - 457** | 4-year cycle trim | Phased approach – 400 Supplemental Miles in 2020, 500 in 2021 and 700 in 2022 and beyond | Phased approach – mid-cycle on feeders only in 2021 and 2022, mid-cycle on full circuits in 2023 and beyond |

Upon finding an optimal endpoint, TECO examined the resource implications of the program and adapted the approach to phase in both the supplemental trimming initiative and the mid-cycle initiative to allow for a smooth transition into the program.

Prior to running the various scenarios, TECO engaged Accenture to refresh the TTM configuration and the various assumptions built into the TTM Storm Module. The configuration process and associated assumptions are captured in Section 6: Tree Trimming Model & Modules Configuration.

# 4 Storm Protection Initiatives Analysis

TECO and Accenture analyzed several vegetation management activities to determine an optimal level of supplemental trimming to reduce vegetation related outages during extreme weather events while continuing to minimize day-to-day vegetation related outages.

The following initiatives were considered:

**Table 4-1: Vegetation Management Initiatives Analyzed**

| | Initiative Name | Initiative Description | Modeling Methodology |
|---|---|---|---|
| **1** | Baseline: 4-Year Effective Cycle | Trim 25% of TECO's overhead lines (~1,562 miles) annually. | Target 25% of the miles in each of TECO's 7 districts for trimming annually. |
| **2** | Supplemental Circuit Trimming | Trim an additional 100 – 900 targeted miles annually with a view to mitigating outage risk on those circuits most susceptible to storm damage | Five scenarios modeled – 100, 300, 500, 700 and 900 miles. Due to the nature of the algorithm and available targeting data, targeting is based on SAIFI performance in regular weather. |
| **3a** | Mid-cycle VM Initiative – Feeders Only | Add mid-cycle inspections to feeder portions of circuits (~35% of line miles) two years after trim, prescribing additional VM activities to a fraction of the trees inspected. | The TTM Enhanced Storm Module assumes that one quarter of the trees inspected will be targeted for re-trimming when inspected and promptly trimmed. As TTM works with miles of circuit rather than individual trees, this is modeled as one quarter of the feeder miles re-setting to trimmed in that year, while the remainder of the circuit continues to age. Within the model, the costs associated with day-to-day restoration, storm restoration, and corrective maintenance costs are re-calculated to reflect the new trim-age profile of the circuit. |
| **3b** | Mid-cycle VM Initiative – Full Circuits | Extend the inspection and prescribed activities described in Initiative 3a to the entire circuit. As with 3a, it is assumed that a fraction of the trees inspected will require mid-cycle VM activities. | As described above in Initiative 3a, TTM Enhanced Storm Module assumes one quarter of the entire circuit is re-trimmed at two years, with an impact on day-to-day restoration costs, storm restoration costs and corrective maintenance costs. |

The Supplemental Circuit Trimming initiative seeks to reduce tree-caused outages by reducing the proximity between tree limbs and lines, as well as reducing trees' sail area which would otherwise cause them to sway or break as wind speed increases.

The Mid-cycle VM initiative focuses on some of the same proximity and sail area reduction efforts on the trees which grow the quickest and may encroach on lines despite the best efforts of the trimming cycle and supplemental trimming, as well as other activities to slow tree growth or eliminate hazard trees altogether.

## 4.1 Baseline Trim Cycle and Initiative 1 Variants

TECO and Accenture ran the company's ongoing 4-year cycle trim through the model to project its full budget implications across seven categories of cost to form a baseline against which the incremental benefits of supplemental trimming activities can be measured. The associated costs are broken out as follows, along with indicators as to whether the cost component in question is part of the VM budget and whether the costs are associated uniquely with VM resources or, as in the case of outage restorations, extend further into the organization:

**Table 4-2: Cost Categories**

| Cost Category | Applies to what resources? | Part of Storm Protection Program | Part of VM Budget? |
|---|---|---|---|
| **Cycle Trimming** | Vegetation | Yes | Yes |
| **Supplemental Trimming** | Vegetation | Yes | Yes |
| **Mid-Cycle** | Vegetation | Yes | Yes |
| **Corrective Cost** | Vegetation | No | Yes |
| **Resource Premiums** | Vegetation | Yes | Yes |
| **Day to Day Restoration Costs** | Line & Vegetation | No | No |
| **Storm Restoration Costs** | Line & Vegetation | No | No |

Note that the anticipated spending levels for the two categories of restoration cost are driven by vegetation management decisions but are not part of the vegetation management budget. They are considered and presented within this analysis because the investments in enhancing vegetation management for the Storm Protection Plan should be offset by reductions in cost due to outage response.

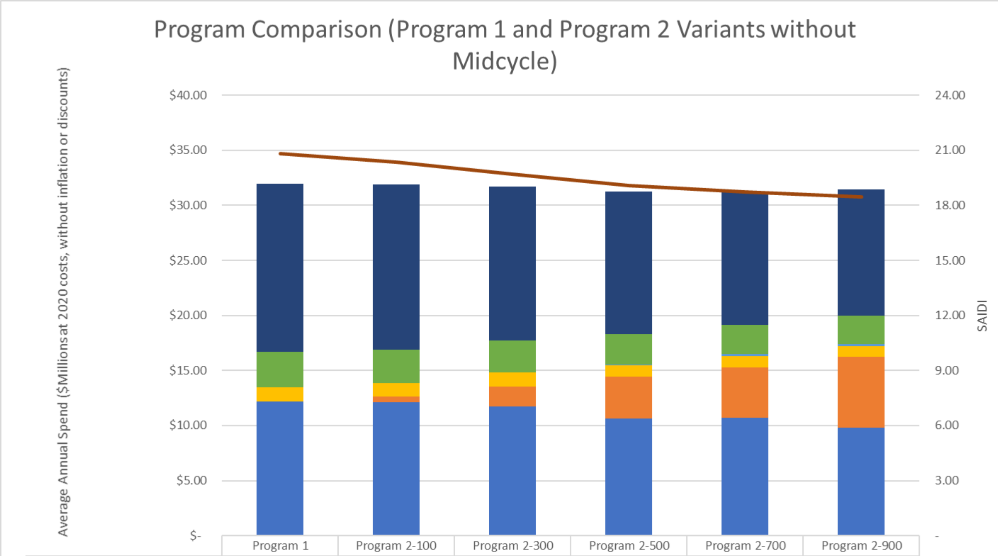
In the baseline scenario, each service area is allotted one quarter of its mileage every year, or approximately 1,562 miles in total. Central, for example, accounts for one sixth of TECO's overhead miles, and is afforded one sixth of the annual 1,562-mile budget as depicted below.

**Table 4-3: Baseline 4-Year Effective Cycle Mileage Targets**

| Service Area | Mileage Target | Percentage |
|---|---|---|
| **Central** | 260 | 16.6% |
| **Dade City** | 93 | 6.0% |
| **Eastern** | 209 | 13.4% |
| **Plant City** | 310 | 19.8% |
| **South Hillsborough** | 182 | 11.7% |
| **Western** | 277 | 17.7% |
| **Winter Haven** | 231 | 14.8% |
| **Total** | 1,562 | 100.0% |

In the supplemental trimming initiatives, one quarter of the supplemental miles is allocated across the service areas in the same proportions as the 4-year distribution trim cycle. The remainder of the miles are directed where they will deliver the greatest benefit. Thus, in a scenario where 400 supplemental miles were trimmed, 100 miles would be constrained with 16.6 occurring in Central, 6.0 miles in Dade City, 13.4 miles in Eastern, and so on with the remaining 300 miles of trimming directed to the areas where it would deliver the greatest benefit.

The costs for the baseline scenario and five variants of supplemental trimming, without mid-cycle, are plotted below:




| | Program 1 | Program 2-100 | Program 2-300 | Program 2-500 | Program 2-700 | Program 2-900 |
|---|---|---|---|---|---|---|
| Storm Restoration Cost | $15.31 | $14.99 | $13.97 | $12.92 | $12.08 | $11.42 |
| Day-to-Day Restoration Cost | $3.19 | $3.05 | $2.91 | $2.77 | $2.69 | $2.63 |
| Resource Premiums | $- | $0.03 | $0.00 | $0.05 | $0.14 | $0.15 |
| Corrective Cost | $1.30 | $1.23 | $1.30 | $1.08 | $1.03 | $0.99 |
| Mid-Cycle Cost | $- | $- | $- | $- | $- | $- |
| Supplemental Trimming Cost | $- | $0.50 | $1.80 | $3.81 | $4.62 | $6.44 |
| Baseline 4-Year Cycle Cost | $12.19 | $12.10 | $11.72 | $10.61 | $10.69 | $9.79 |
| SAIDI | 20.83 | 20.36 | 19.70 | 19.09 | 18.75 | 18.45 |

**Figure 4-1: Program Comparison**

The average annual vegetation management budget, without inflation, for these six options ranges from $13.5M for the as-is 4-year trimming cycle to $17.4M for the cycle plus 900 miles of supplemental trimming annually. Meanwhile the annual total restoration costs, which include all line work and vegetation management costs for storm restoration, trend in the opposite direction from $18.5M for the baseline 4-year cycle to $14.1M for the 900-mile variant. The total anticipated cost of the VM budget and restoration combined sits in a narrower range, at $32.0M for the baseline 4-year cycle and $31.25 M for the 500 and 700-mile variants.

The side-by-side comparison of scenarios yields several insights:

- The introduction of supplemental trimming drives down the cost of the baseline four-year cycle. This is because the extra activity on the lines makes trimming the annual 1,562 miles less expensive each year since the tree limbs have had less time to grow and are neither as long nor as close to the lines as they would have been otherwise.
- The increases in cost associated with the Storm Protection Program 2 variants and associated resource premiums is offset by decreases in cost in the 4-year cycle trim, corrective maintenance, day-to-day restoration costs and storm restoration costs, up to the 500 to 700-mile range.
- Although difficult to see in Figure 4-1, the 500 mile and 700-mile programs yield the best overall average annual cost, which, due to diminishing returns, begins to trend back upwards starting with the 900-mile program. See Figure 4-2, below, for a view focused on total cost.
- Each supplemental increase in Program 2 yields an improvement in SAIFI and SAIDI, although the gains slow in the 500-mile to 700-mile range.

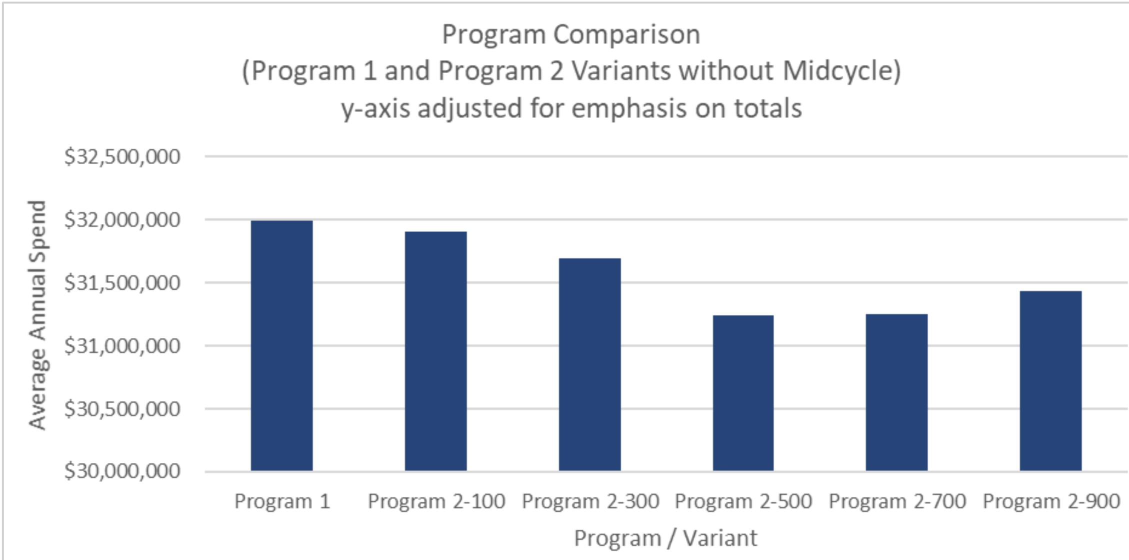



**Figure 4-2: Program Comparison with Focus on Total Average Annual Spend**

- While the 500 mile and 700-mile programs are in a virtual tie from an overall cost perspective, there is a clear advantage to the 700-mile program from the customer experience perspective. The 700-mile program drives 16 percent and 21 percent improvements in the ten-year average day-to-day and storm restoration costs, which are directly linked to customer interruptions. Across the ten-year span of the 500-mile program, these figures are 13 percent and 16 percent.

**Table 4-4: 10-year Average Outage Restoration Improvements for Programs 2-500 and 2-700 Relative to Program 1**

| Cost Element | Program 1 Average 2020-2029 | Program 2-500 Average 2020-2029 | Program 2-700 Average 2020-2029 | Improvement for Program 2-500 | Improvement for Program 2-700 |
|---|---|---|---|---|---|
| **Day-to-Day Restoration** | $3.19 M | $2.77 M | $2.69M | 13.2% | 15.7% |
| **Storm Restoration** | $15.31 M | $12.92M | $12.08M | 15.6% | 21.1% |

## 4.2 Storm Protection Initiative 3a & 3b – Mid-cycle Inspection and VM Activities

Based on the results presented in Section 4.1, Initiatives 3a and 3b were analyzed in the context of Program 2-700, where 700 supplemental and targeted miles are trimmed each year. The average annual cost of the inspectors and VM resources for the mid-cycle initiatives was $1.06M and $4.05M, respectively, and they yielded a further 2.5 percent and 4.5 percent improvements to storm restoration costs from $12.08M to $11.77M and $11.54M.

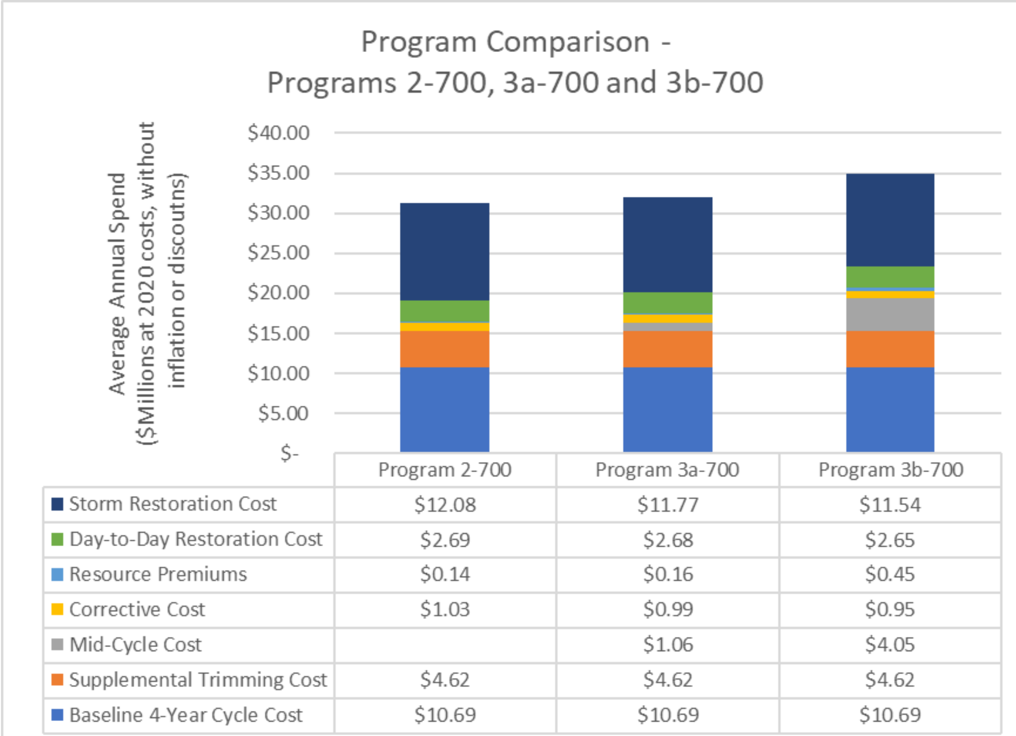



**Figure 4-3: Storm Protection Program Mid-Cycle Comparison**

**Table 4-5: 10-year Average Outage Restoration Improvements for Programs 3a-700 and 3b-700 Relative to Program 2-700**

| Cost Element | Program 2-700 Average 2020-2029 | Program 3a-700 Average 2020-2029 | Program 3b-700 Average 2020-2029 | Improvement for Program 3a-700 | Improvement for Program 3b-700 |
|---|---|---|---|---|---|
| **Storm Restoration** | $12.08M | $11.77M | $11.54M | 2.6% | 4.5% |
| **Day-to-Day Restoration** | $2.69M | $2.68M | $2.65M | 0.4% | 1.5% |

As noted previously, the modeling approach may not reflect the full value of the mid-cycle activities. While the Tree Trimming Model considers circuits in their entirety, the mid-cycle initiative would be targeted based on inspections and storm impact and is highly likely to yield greater benefits than what is reflected here. Also, some of the prescribed activities under the mid-cycle initiative, such as tree removals, will yield permanent and cumulative results not captured here. Simply put, it is believed that the benefits of the mid-cycle initiative will exceed what is shown here.

## 4.3 Developing a Blended Strategy to Accommodate Resource Constraint

Resource impact is one final element to draw out of the Storm Protection Program 2 and Storm Protection Program 3a/3b analyses. The 500, 700, and 900-mile versions of Storm Protection Program 2 all incur cost premiums associated with the rapid increase in size to the workforce required. Programs

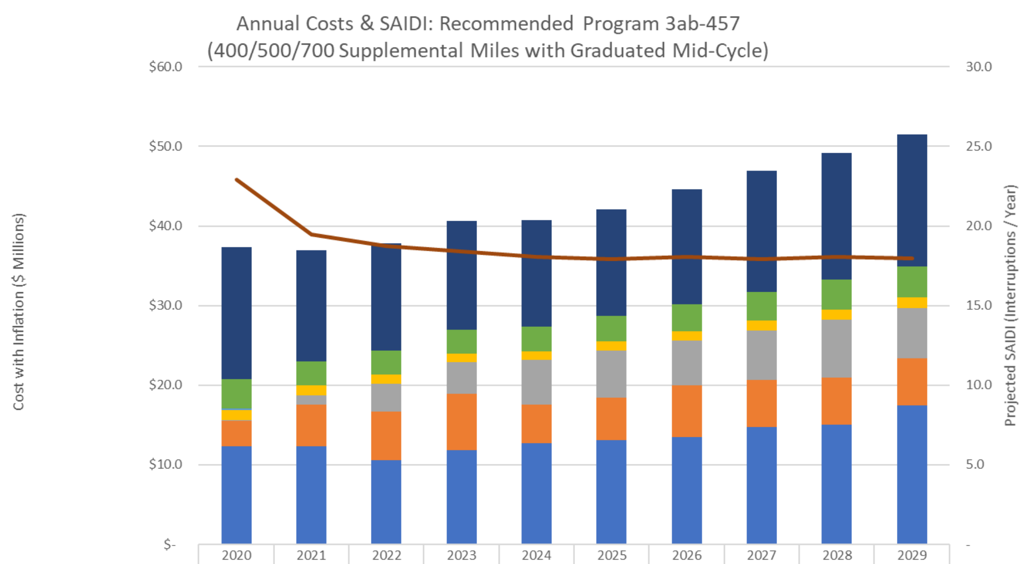
3a-700 and 3b-700 exacerbate the resource crunch. While the average annual VM budget (without inflation) for Program 2-700 (Baseline + 700 supplemental miles) is estimated at $16.4M and would require an average of 220 resources to execute, the first year VM budget would be $19.0M and require roughly 256 resources. With 196 resources in the field at present, the uptake of 60 workers in a single year would represent a very large challenge and require significant expenditure on overtime and premium incentives to achieve, particularly if the transition happens later in the year. Adding Initiative 3a or 3b simultaneously would further exacerbate the issue.

TECO is proposing instead to transition towards the 700-mile version of Initiative 2 over the course of three years by trimming 400 extra miles in 2020, 500 extra miles in 2021 and finally arriving at the 700-mile program in 2022. The mid-cycle initiative will also be introduced gradually, addressing feeders alone in the second and third years and moving towards inspecting full circuits in the fourth year and beyond as better data becomes available about the success of mid-cycle inspections and VM activities.

# 5 Recommendation

The recommended Vegetation Management Storm Protection Program (Program 3ab-457) consists of the following activities:

1) **Baseline Cycle**: continue the 4-year trimming cycle
2) **Supplemental trimming initiative**: scale up supplemental trimming miles by targeting an additional 400 miles in 2020, 500 miles in 2021, and 700 miles from 2022 going forward
3) **Mid-cycle VM initiative**: introduce mid-cycle inspections and associated targeted activities for the feeder portions of circuits in 2021, extending the inspections and prescribed activities to cover entire circuits from 2023 forward, with 60 miles inspected in 2021, 48 miles in 2022 and 254 miles in 2023 as the program rolls out to entire circuits.




| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Storm Restoration Cost | $16.6 | $13.9 | $13.5 | $13.6 | $13.3 | $13.4 | $14.4 | $15.3 | $16.0 | $16.6 |
| Day-to-Day Restoration Cost | $3.6 | $3.0 | $2.9 | $3.0 | $3.1 | $3.2 | $3.4 | $3.5 | $3.7 | $3.9 |
| Resource Premiums | $0.2 | $- | $- | $- | $- | $- | $- | $- | $- | $- |
| Corrective Cost | $1.3 | $1.3 | $1.2 | $1.1 | $1.1 | $1.1 | $1.2 | $1.2 | $1.3 | $1.3 |
| Mid-Cycle Cost | $0.1 | $1.2 | $3.5 | $4.0 | $5.6 | $6.0 | $5.7 | $6.2 | $7.3 | $6.3 |
| Supplemental Trimming Cost | $3.2 | $5.2 | $6.1 | $7.1 | $4.8 | $5.3 | $6.5 | $5.9 | $5.9 | $5.9 |
| Baseline 4-Year Cycle Cost | $12.4 | $12.3 | $10.5 | $11.8 | $12.7 | $13.1 | $13.4 | $14.7 | $15.0 | $17.5 |
| SAIDI | 22.9 | 19.5 | 18.8 | 18.4 | 18.1 | 17.9 | 18.1 | 17.9 | 18.1 | 18.0 |
| Estimated Resource Requirement | 228 | 257 | 262 | 280 | 270 | 270 | 270 | 270 | 270 | 270 |

**Figure 5-1: Annual Costs and SAIDI – Recommended VM Program**

The VM Budget (SPP and Non-SPP) and Restoration Costs are summarized below:

**Table 5-1: VM Storm Protection Program 3ab-457 Performance Characteristics**

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total VM Budget | $17.1 | $20.0 | $21.4 | $24.0 | $24.3 | $25.5 | $26.8 | $28.1 | $29.5 | $31.0 |
| Restoration Costs | $20.3 | $17.0 | $16.5 | $16.6 | $16.4 | $16.6 | $17.8 | $18.8 | $19.7 | $20.5 |
| Total VM-Influenced Costs | **$37.4** | **$36.9** | **$37.9** | **$40.6** | **$40.7** | **$42.1** | **$44.6** | **$46.9** | **$49.2** | **$51.5** |

From a benefits perspective, two measures are worth exploring because the program takes a few years to establish: the overall ten-year average performance, and the future steady-state value taken in this case by considering the average of the last five years in the analysis. For the 10-year and 5-year end state averages, all years and cost elements are priced at 2020 rates, with no inflation.

**Table 5-2: VM Storm Protection Program 3ab-457 Performance Characteristics**

| | 10-Year Average | | | Future Steady-State (Average of Last Five Years) | | |
|---|---|---|---|---|---|---|
| | Program 1 | Program 2-457 | Program 3ab-457 | Program 1 | Program 2-457 | Program 3ab-457 |
| **SAIFI** | 0.229 | 0.195 | 0.193 | 0.227 | 0.184 | 0.181 |
| **SAIDI** | 20.8 | 18.9 | 18.8 | 20.7 | 18.2 | 18.0 |
| **Typical Storm Season** | $15.3 M | $12.4 M | $11.9M | $15.1 M | $11.4 M | $10.7 M |
| **65 mph Storm** | $16.6 M | $14.0 M | $13.3 M | $16.3 M | $13.2 M | $12.4 M |
| **85 mph Storm** | $37.1 M | $31.3 M | $29.8 M | $36.5 M | $29.6 M | $27.6 M |
| **105 mph Storm** | $69.9 M | $59.0 M | $56.1 M | $68.7 M | $55.7 M | $52.1 M |
| **125 mph Storm** | $117.9 M | $99.5 M | $94.6M | $109.8 M | $94.0 M | $87.9 M |

The proposed Program 3ab-457 is projected to improve SAIFI by 15.3 percent relative to the baseline 4-year cycle over the full period, or by 21.3 percent if just the final five years are considered. SAIDI improvement is 9.6 percent across ten years, or 14.0 percent in the future steady state. Storm performance improves by 22.2 percent across ten years, or 29.1 percent in the future steady state.

# 6 Tree Trimming Model & Modules Configuration

The Tree Trimming Model requires intermittent updates wherein the latest circuit configuration, trimming and outage history are employed to ensure the model is using the latest information available when targeting circuits for trimming. In addition, the storm module requires updates to a variety of cost and workforce assumptions to perform its functions correctly.

## 6.1 TTM Inputs and Assumptions

TTM requires three principal data sources:

- A complete inventory of the overhead circuits in the system, including circuit characteristics such as customer count, overhead mileage, and geographic coordinates;
- The outage database or databases; and,
- A history of trimming activity, preferably including start and end dates, costs, and covering multiple trims for each circuit.

### 6.1.1 Circuit List

A comprehensive list of circuits was obtained from TECO, which contained a total of 780 circuits.

Not all circuits and mileage were of interest, as TTM is only relevant to the overhead portion of circuits for which trimming is a regular concern. Ultimately, 709 “trimmable” circuits were included in the analysis, representing some 6,247 miles of overhead circuit length.

### 6.1.2 Performance Data

Circuit reliability performance data was gathered from TECO’s Distribution Outage Database (DOD). The analysis included outages from January 1, 2006 through November 26, 2019, thus accommodating at least thirteen years of data. Of interest were outages with the tree-related cause codes found in Table 6-1below. The table indicates the number of events associated with each cause code, as well as the total customer interruptions (CI) and customer minutes of interruption (CMI).

**Table 6-1: Tree-Related Cause Codes (January 1, 2006 - November 26, 2019)**

| Cause Code | Events | CI | CMI |
|---|---|---|---|
| **Tree\Blew into Line** | 305 | 20,060 | 1,219,189 |
| **Tree\Non-Prev.** | 9,970 | 811,842 | 68,744,420 |
| **Tree\ Prev.** | 9,776 | 740,361 | 66,143,332 |
| **Tree\Grew into Line** | 1,644 | 110,815 | 8,404,342 |
| **Tree\Vines** | 5,984 | 210,380 | 7,476,754 |
| **Trees (Other)** | 436 | 22,815 | 1,879,906 |
| **Incorporated Unknown** (25%) | 2,732 | 162,248 | 10,206,418 |
| **Incorporated Weather** (25%) | 6,190 | 389,703 | 35,775,171 |
| **Grand Total** | 37,037 | 2,468,224 | 199,849,532 |

TECO also incorporated a portion of CIs and CMIs from outages with “Unknown” and “Weather” cause codes. From experience, Accenture has found with other utilities that a significant portion of such catch-all causes is, in fact, tree-related. Therefore, after conducting an internal analysis of trends in outage counts for these cause codes in relation to explicit tree cause codes, TECO determined that 25 percent was a reasonable proportion to include in the analysis.

Finally, certain outages were excluded from this analysis irrespective of the cause code. These included those adjustments specified and allowed in accordance with Rule 25-6.0455, Florida Administrative Code.

### 6.1.3 Trim Data

TECO records and maintains trim history that includes the following types of data:

- Circuit number;
- Trim start date;
- Trim completion date;
- Miles trimmed; and,
- Cost to trim the entire circuit.

Similar to the performance data, the analysis included trimming data from January 1, 2006 through November 26, 2019. The trim data was pared down to the outage data with the circuit number being the link between the two data sources. For analysis purposes, the circuit number and trim completion date (year and month of trim) of each circuit trim were incorporated in the analysis.

## 6.2 Reliability Performance Curve Development

### 6.2.1 Creating Circuit Performance Groups

Circuits were ordered according to historical performance. A total of seven groups were identified so that around 1,130 miles were represented in each group. Group 07 were the circuits that had zero tree-related outages from 2006-2019.

**Table 6-2: CI Grouping Characteristics**

| Circuit CI Group | CI per Mile Criteria | Circuits | Miles |
|---|---|---|---|
| **01** | Greater than 649 | 164 | 1,117 |
| **02** | Between 467 and 649 | 95 | 1,135 |
| **03** | Between 277 and 467 | 131 | 1,136 |
| **04** | Between 193 and 277 | 70 | 1,134 |
| **05** | Between 104 and 193 | 101 | 1,132 |
| **06** | Between 0.3 and 104 | 168 | 1,130 |
| **07** | Less than 0.3 | 66 | 19 |

**Table 6-3: CMI Grouping Characteristics**

| Circuit CI Group | CMI per Mile Criteria | Circuits | Miles |
|---|---|---|---|
| **01** | Greater than 55,483 | 159 | 1,130 |
| **02** | Between 34,277 and 55,483 | 114 | 1,125 |
| **03** | Between 22,485 and 34,277 | 114 | 1,107 |
| **04** | Between 14,427 and 22,485 | 83 | 1,133 |
| **05** | Between 8,340 and 14,427 | 87 | 1,152 |
| **06** | Between 19.3 and 8,340 | 172 | 1,136 |
| **07** | Less than 19.3 | 66 | 19 |

### 6.2.2 Circuit Performance Curve Fitting

Performance data points were derived using historical outage data, trim data, and circuit length data. Every outage was expressed as a number of CI or CMI per circuit mile and was plotted relative to the most recent time it was trimmed. Values for 12 consecutive individual months were rolled up to create year-based values, and these were plotted in MS Excel so that a curve could be fit to them.

Several conditions had to be satisfied in order to ensure that the data points were correct:

- Outage data was omitted in the months when a circuit was being trimmed.

- Outages were associated only to the most recent trim.
- Figure 6-1 below reflects the mileage into which the 12-month roll-up of CI or CMI is divided and represents the total mileage of the system or group of circuits. This ensures that in a situation where several circuits do not have any outages in a particular 12-month roll-up, those circuits were not disregarded, but rather served to appropriately pull the curve downward as part of the averaging process. This provided assurance that the resulting curves were representative of the overall CI or CMI per mile of circuits in the group and not just the CI or CMI per mile on circuits that happened to have outages.

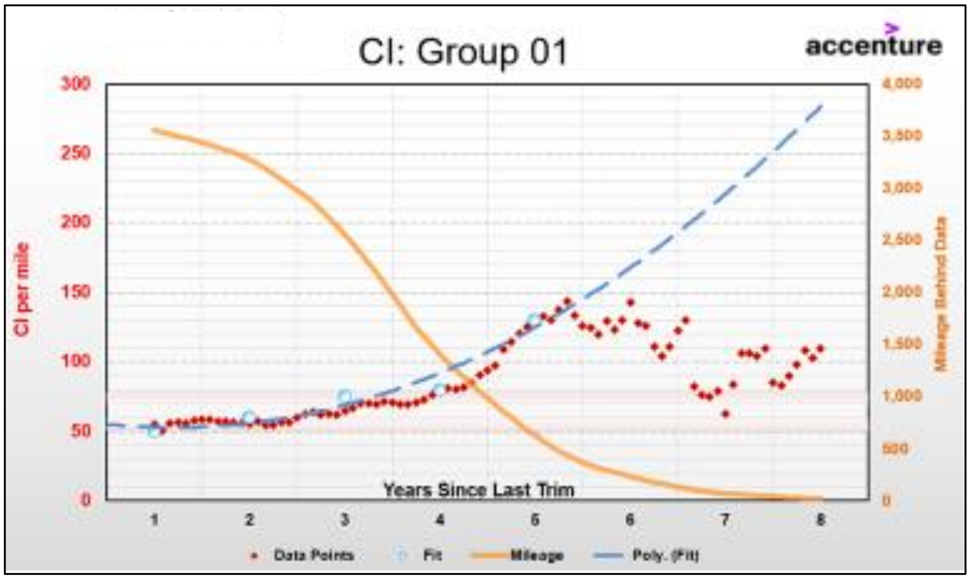



**Figure 6-1: Example of Curve Fitting Analysis**

A curve similar to that shown in Figure 6-1 was developed for each of the CMI groups, resulting in a total of fourteen curves, which are shown in Figure 6-2 and Figure 6-3 respectively. These curves provided the critical input required to compute the projected reliability associated with trimming each circuit. Eventually, the computed reliability values were used as the denominator to determine the cost-effectiveness score for circuits, which then served as the basis for their prioritization.

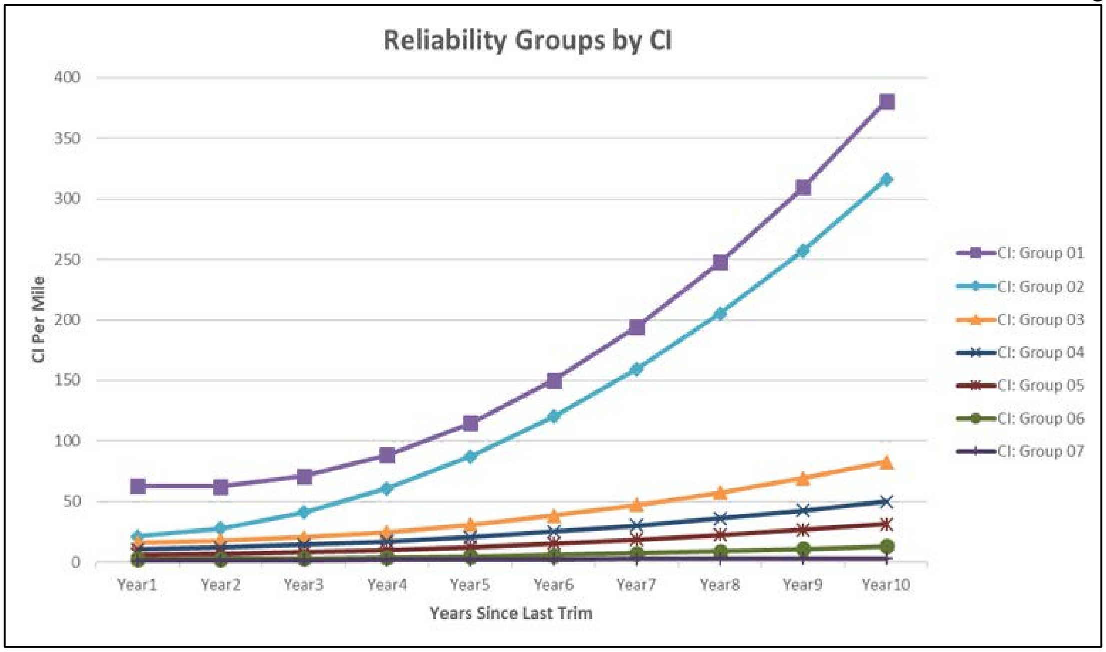



**Figure 6-2: Customer Interruption (CI) Curve Groups**

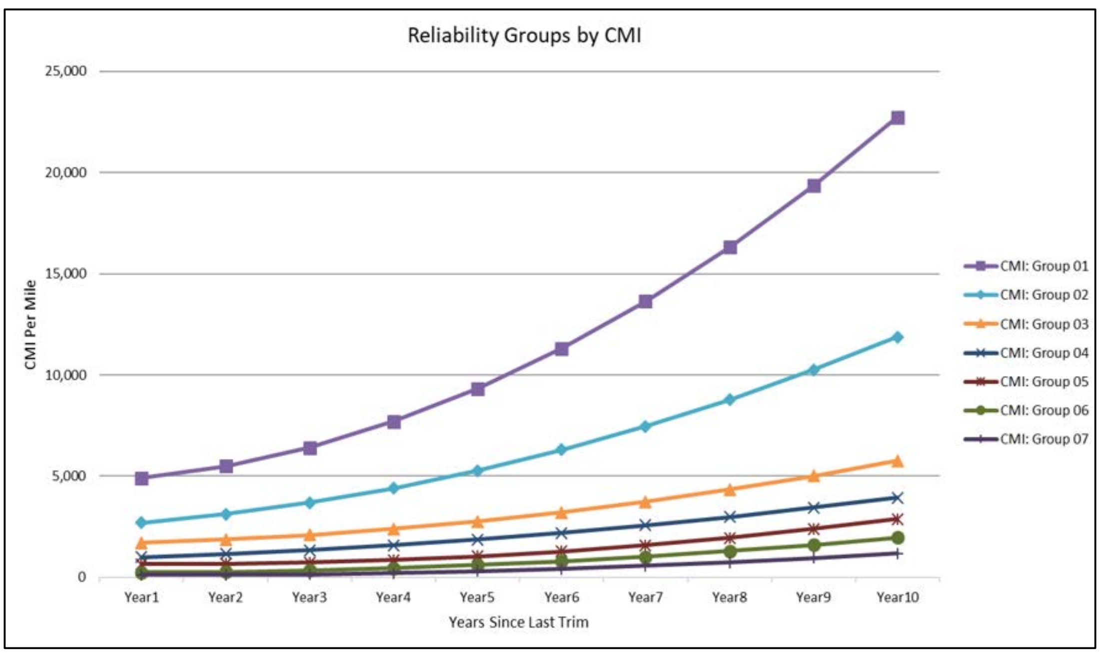



**Figure 6-3: Customer Minute Interruption (CMI) Curve Groups**

### 6.2.3 Cost Curves

Cost curves were the second factor in calculating the cost/benefit score of each circuit in TTM.

The shapes of the cost curves were based on a proprietary study called the Economic Impacts of Deferring Electric Utility Tree Maintenance by ECI[9] that quantified the percentage increase in the eventual cost of trimming a circuit for each year that it is left untrimmed beyond the recommended clearance cycle. The findings of the ECI study are summarized in Figure 6-4 below. For instance, if the clearance cycle is three years, then waiting four years between trims will increase the cost per mile by 20 percent. Delaying trimming by another year will further inflate costs to 40 percent of the base cost and further increase it for subsequent years.

The ECI study only considered annual trimming cost increases between the recommended clearance cycle and up to a four-year delay. In generating a comprehensive cost curve that goes from one year since last trim onward, Accenture supplemented the percentages from the ECI study with two assumptions:

- Cost reduction from annual trimming – the percentage reduction from the clearance trim that will be achieved if the circuit was trimmed every year; and,
- Escalation – annual percentage increase in cost to be applied from the ninth year and beyond.

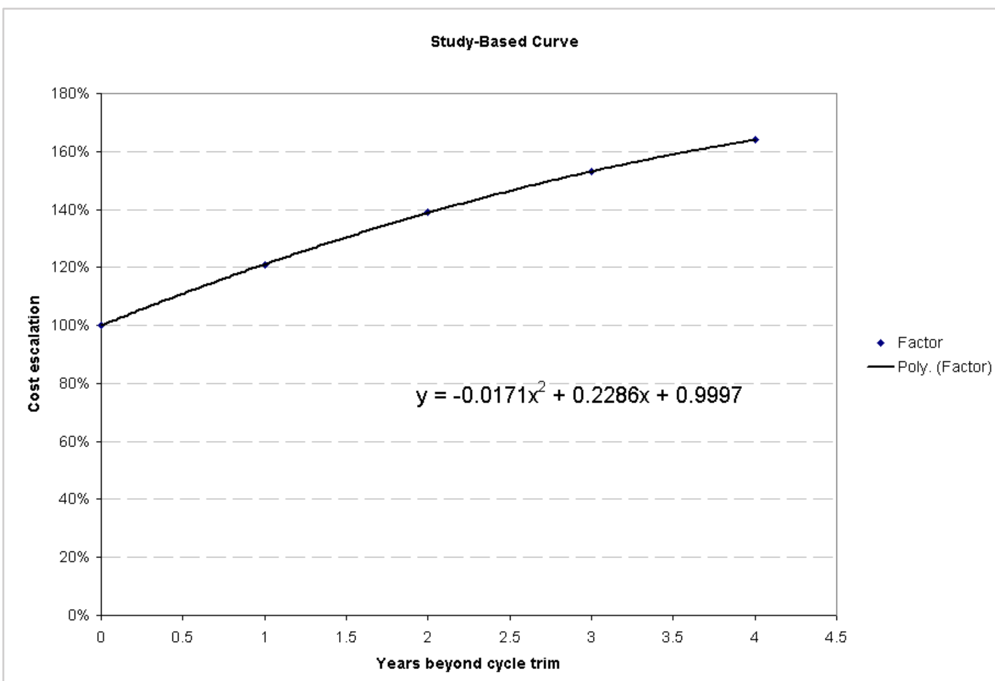



**Figure 6-4: ECI Study-Based Cost Curve**

The following section describes how such a cost curve methodology was applied to each cost group.

[9] Browning, D. Mark, 2003, Deferred Tree Maintenance, Environmental Consultants Incorporated (ECI)

Similar to how the performance groups were created, circuits were ordered according to the average cost per mile. Initially a total of six groups were identified so that each had around 1,000 miles represented in each group. Group 01 ranged from $7,600/mile to $41,000/mile and it was important to further divide it into smaller groups due to the large range between costs. Ultimately, Group 01 was divided into 4 smaller groups so that the ranges were more reasonable. The same was true on the other side of the spectrum and the lowest cost group was split into two groups. Ultimately, circuits were grouped into 10 distinct groups as shown in the following table:

**Table 6-4: Cost Grouping Characteristics**

| Circuit Cost Group | Cost per Mile Criteria | Circuits | Miles |
|---|---|---|---|
| **01** | Greater than $25,000 | 14 | 79 |
| **02** | Between $15,500 and $25,000 | 26 | 158 |
| **03** | Between $10,000 and $15,500 | 42 | 225 |
| **04** | Between $7,600 and $10,000 | 90 | 713 |
| **05** | Between $6,100 and $7,600 | 103 | 1,088 |
| **06** | Between $5,000 and $6,100 | 109 | 1,016 |
| **07** | Between $4,100 and $5,000 | 91 | 1,037 |
| **08** | Between $3,300 and $4,100 | 89 | 1,058 |
| **09** | Between $1,500 and $3,300 | 116 | 896 |
| **10** | Less than $1,500 | 25 | 100 |

With this group information a curve was created for each using the average cost per mile in each group with an additional twenty-five percent increase on each. The additional twenty-five percent was added to adjust historical trimming costs to 2019 dollars. Since TECO is on a four-year effective trim cycle each cost group is anchored on Year 4 with its respective adjusted average cost per mile. The remaining points were determined using the expertise of TECO and Accenture:

- Years 1: A 35 percent reduction in average cost if TECO would return to a circuit a year later
- Years 2-3: Linear increase in spending from Year 1 to Year 4
- Years 5-8: Follow the cost escalation described in Figure 6-5.
- Years 9-10: A 5 percent increase for each year trimming is delayed

These datapoints and assumptions were used to fit a curve for each of the cost groups shown below:

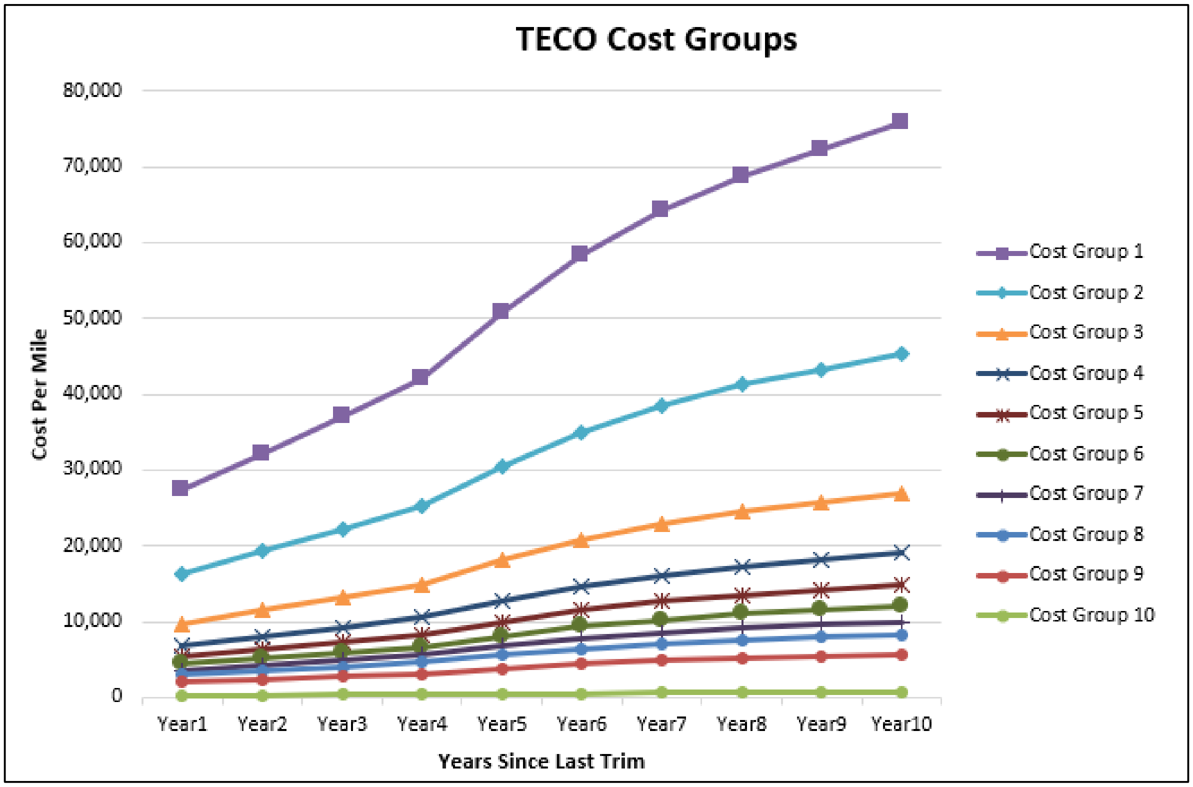



**Figure 6-5: Cost Groups**

TTM uses these curves to identify the estimated cost per mile to trim a circuit based on its year since last trim. These costs are in 2019 dollars and an estimated 5 percent inflation rate is used for subsequent trimming costs in future years.

## 6.3 Storm Module Inputs and Assumptions

Storm protection initiative cost and benefit modeling was accomplished using TTM and its associated Storm Module which have been used to prioritize trimming activities since 2006, and an Enhanced Storm Module to cover analyses not originally anticipated in the original Storm Module. The following cost implications were generated for each vegetation management activity considered:

**Table 6-5: Storm Module Cost Assumptions**

| Cost | Cost Generator | Key Assumptions |
|---|---|---|
| **Baseline: 4-Year Cycle Cost** | TTM Core Module | • Cost curves (TTM Configuration Analysis)<br>• Years since last trim (TECO records)<br>• Proportional allocation of mileage across work areas |
| **Supplemental Trimming Cost** | TTM Core Module | • Cost curves (TTM Configuration Analysis)<br>• Years since last trim (TECO records)<br>• Proportional allocation of mileage across work areas for 25% of supplemental miles |
| **Mid-Cycle VM Initiative Cost** | TTM Enhanced Storm Module | • Cost premium for inspection and enhanced activities (SME Estimate)<br>• Timing of mid-cycle activities (SME decision)<br>• Proportion of circuit population targeted (SME decision – 2 scenarios)<br>• Proportion of circuit targeted (SME decision) |
| **Corrective Maintenance Tickets** | TECO Subject Matter Expert Input | • Proportion of corrective maintenance tickets attributable to tree growth (TECO Records)<br>• Relationship between tree growth corrective maintenance tickets and system effective cycle (SME estimate, past filings) |
| **Premiums Associated with Attracting Additional Workforce** | TTM Core Module | • VM budget (Cycle + Supplemental + Mid-Cycle + Corrective)<br>• Straight and overtime loaded cost rates for VM crews (SME estimate)<br>• Maximum organic growth rate of the VM workforce (SME estimate)<br>• Productivity adjustment for training new VM resources (SME estimate)<br>• Incentive costs for VM resources required beyond the organic growth capacity (SME estimate) |
| **SAIDI-Driven Restoration Costs** | TTM Storm Module | • Reliability outputs from TTM Core Module<br>• Average cost to restore a CMI (SME estimate) |
| **Storm Restoration Costs** | TTM Storm Module | • Trim list from TTM Core Module<br>• Storm damage calculation function<br>• FEMA HAZUS windspeed return dataset |

| Cost | Cost Generator | Key Assumptions |
|---|---|---|
| | | • Average cost to restore in major event including mutual assistance (Irma Analysis, SME adjustment) |

### 6.3.1 Baseline: 4-Year Cycle Costs

Routine cycle trimming costs are projected by the Tree Trimming Model based on curves derived in the model configuration stages.

Cycle targets are established by declaring a number of miles to trim each year. In the baseline four-year scenario, the budget was allocated such that each service area would be on its own four-year cycle.

### 6.3.2 Supplemental Trimming Costs

Supplemental trimming costs are projected by the Tree Trimming Model based on curves derived in the model configuration stages.

In all supplemental scenarios, each service area was guaranteed their allocation of one quarter of the supplemental miles, with the remaining three-quarters of the miles getting targeted to where they were most needed.

### 6.3.3 Mid-Cycle Costs

There are four key assumptions relating to mid-cycle trimming activities:

- The cost premium for inspection and targeted trimming relative to cycle activities
- The timing of mid-cycle activities
- The portions of circuits to target
- The fraction of trees which will require mid-cycle intervention

Inspection-based activities come at a premium. There is first the cost of patrolling and inspecting the lines before vegetation management activities are taken, which must then be loaded into the costs of performing the actions in question. Second, relative to regular maintenance trimming, there are cost inefficiencies to trimming selectively. In regular maintenance trimming, vegetation crews can trim multiple trees each time they set up their vehicle and raise the bucket. In selective trimming, the ratio of setup time to actual wood removal goes up, further increasing the per-unit cost. Based on an analysis of corrective maintenance tickets, the TECO subject matter experts estimated that mid-cycle trimming would cost 80 percent more on a per-tree basis than routine trimming.

Mid-cycle activities are timed to promote the best possible performance out of the routine trimming initiative. Based on TECO subject matter expert input and considering the intervals between trimming in the baseline and enhanced scenarios, two years was selected as the optimal time for a mid-cycle inspection and associated vegetation management activities.

Mid-cycle activities will have similar impact in terms of overall restoration effort in a major event whether they occur on the feeder or lateral. Activities on the feeder will, however, protect more customers per tree outage avoided. With this in mind, TECO subject matter experts specified two possible scopes for Initiative 2 – feeder miles and all miles to be considered in that order.

The final component of scoping this cost was to predict the maximum number of trees to be targeted for mid-cycle activities as a result of the inspections. TECO subject matter experts estimated up to 25 percent of trees would grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. The analysis uses this figure but presumes that additional activities may be substituted for portions of the potential trimming, such as performing removals and the like, as long as the activities fit within the stipulated budget. As the cost per tree is 180% of regular trimming cost, and only 25 percent of trees can be targeted for mid-cycle activity, this should never amount to greater than 45% (180% * 25%) of the regular 4-year cycle budget.

### 6.3.4 Corrective Costs

TECO responds to approximately 4,000 corrective maintenance tickets annually, of which one third are related to tree limbs growing too close to the wires. The remainder are related to various forms of capital work, moving lines to accommodate construction, and the like. In total, the corrective maintenance tickets currently amount to $1.3 million per year, with TECO trimming to a four-year cycle. In prior filings, TECO estimated that moving from a three-year to a four-year cycle would result in a 30 percent increase in corrective maintenance tickets. Conversely, moving from four years back to three years would effectively revert the current $1.3 million budget to $1.0 million, or a roughly 23 percent reduction. Postulating that all growth-related tickets (33 percent) would be eliminated in a two-year cycle, the team fit a curve and generated a set of assumptions as follows, relative to the baseline 4-year scenario:

**Table-6-6: Cost Assumptions by Effective Cycle**

| Effective Cycle (years) | Cost Reduction | Resulting Cost |
|---|---|---|
| **4.00** | 0.0% | $1.30M |
| **3.75** | 7.0% | $1.21M |
| **3.50** | 13.0% | $1.13M |
| **3.25** | 18.5% | $1.06M |
| **3.00** | 23.0% | $1.00M |
| **2.75** | 26.7% | $0.95M |
| **2.50** | 29.6% | $0.91M |
| **2.25** | 31.7% | $0.89M |
| **2.00** | 33.0% | $0.86M |

### 6.3.5 Resource Premium Costs

Experience has shown that there is a limit to the rate at which TECO can expand its workforce without incurring some degree of premium cost. To account for this, the TTM Storm Module estimates the number of resources that would be required to do the Trimming, Mid-cycle and Corrective work in an assumed 2,000-hour work year, and applies a number of cost adjustment factors if that amount is significantly higher than the current size. Cost Premium calculations consider the maximum number of resources that can be added in a given year without offering overtime or a per diem premium, and the assumed productivity of new resources in their first year.

### 6.3.6 Day-to-Day Restoration Costs

A key output of the Tree Trimming Model is the anticipated reliability performance of the system due to vegetation-caused outages in each year of the analysis. The reliability predictions are produced through TTM's CI and CMI configuration curves, which are derived on the basis of several years of outage and tree trimming data.

Outages trigger restoration costs through the use of the dispatch function, line crews and tree crews. The average cost for responding to an outage is estimated at $1,300 and the calculated average number of customers interrupted per vegetation outage is 65, resulting in an estimated average cost per CI due to tree-caused outages of twenty dollars.

Annual restoration costs are estimated multiplying the SAIFI values generated by TTM by the number of customers served by TECO, and in turn multiplying that product by the estimate of $20 per customer interrupted.

### 6.3.7 Storm Restoration Costs

The TTM Storm Module projects storm restoration costs per year using a function which determines the fraction of customers who will experience power loss based on wind-speed experienced and the number of years since the circuit was last trimmed, an amalgam of annual windspeed probabilities derived from FEMA's Hazards-US dataset and an estimate of restoration cost per customer derived from TECO's recent experience with Hurricane Irma.

The TTM Storm Module's central equation is based on a study conducted in southern Florida around 2005 which determined that wind-driven tree outages are influenced by the length of time since last trim. The equation accepts as parameters the wind speed experienced and the number of years since the circuit was last trimmed. The equation returns a percentage which is then applied to the number of customers served by the circuit to come up with an estimate of customers interrupted. In cases of extremely high winds (150 mph and up) and long intervals since last trim, the equation can return values above 100 percent, which is taken to mean that while only 100 percent of the customers on a circuit will be interrupted, the effort to restore them will go beyond the usual cost per customer due to the multitude of damage locations on the circuit.

| Wind Gusts (3 second sustained @10m elevation) | Years Since Last Trim: 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| 40 | 0.19% | 0.48% | 0.83% | 1.21% | 1.63% | 2.08% |
| 45 | 0.27% | 0.69% | 1.18% | 1.73% | 2.32% | 2.96% |
| 50 | 0.38% | 0.94% | 1.61% | 2.37% | 3.18% | 4.06% |
| 55 | 0.50% | 1.23% | 2.13% | 3.15% | 4.24% | 5.40% |
| 60 | 0.65% | 1.63% | 2.79% | 4.09% | 5.50% | 7.01% |
| 65 | 0.82% | 2.07% | 3.53% | 5.20% | 6.99% | 8.91% |
| 70 | 1.08% | 2.58% | 4.43% | 6.49% | 8.74% | 11.13% |
| 75 | 1.27% | 3.18% | 5.43% | 7.99% | 10.74% | 13.69% |
| 80 | 1.54% | 3.88% | 6.61% | 9.69% | 13.04% | 16.61% |
| 85 | 1.84% | 4.63% | 7.93% | 11.63% | 15.64% | 19.93% |
| 90 | 2.19% | 5.49% | 9.42% | 13.80% | 18.57% | 23.66% |
| 95 | 2.57% | 6.46% | 11.07% | 16.23% | 21.84% | 27.82% |
| 100 | 3.00% | 7.54% | 12.92% | 18.93% | 25.47% | 32.45% |
| 105 | 3.47% | 8.72% | 14.93% | 21.92% | 29.48% | 37.56% |
| 110 | 3.99% | 10.03% | 17.19% | 25.20% | 33.90% | 43.19% |
| 115 | 4.56% | 11.46% | 19.63% | 28.79% | 38.73% | 49.35% |
| 120 | 5.18% | 13.02% | 22.32% | 32.71% | 44.01% | 56.07% |
| 125 | 5.86% | 14.72% | 25.23% | 36.98% | 49.74% | 63.38% |
| 130 | 6.59% | 16.56% | 28.38% | 41.59% | 55.95% | 71.29% |
| 135 | 7.38% | 18.54% | 31.78% | 46.58% | 62.66% | 79.84% |
| 140 | 8.23% | 20.68% | 35.44% | 51.95% | 69.88% | 89.04% |
| 145 | 9.15% | 22.98% | 39.38% | 57.72% | 77.64% | 98.93% |
| 150 | 10.13% | 25.44% | 43.60% | 63.90% | 85.95% | 109.52% |
| 155 | 11.17% | 28.06% | 48.10% | 70.50% | 94.84% | 120.84% |
| 160 | 12.29% | 30.87% | 52.91% | 77.55% | 104.31% | 132.91% |

**Figure 6-6: Expected Damage by Wind Gusts for a Given Year Since Last Trim**

The windspeed probabilities employed by the TTM Storm Module are derived from wind speed return values calculated by FEMA in their Hazards-US (HAZUS) package. HAZUS provides a geographically specific listing of windspeeds that can be expected to return to a given location every year, 10 years, 20 years, 50 years, and so on through 1,000 years based on an analysis of tropical storm tracks over several decades. Those data points are transformed to point probabilities for individual windspeeds, from which expectations for given ranges are calculated. The TTM Storm Module is loaded with probabilities every 10 miles from 55 miles per hour through 195 miles per hour, representing the probability of seeing windspeeds in the 50-60 mile per hour range, 60-70 mile per hour range and so on through to the 190-200 mile per hour range.

With an estimate of the expected number of customers to experience outages due to extreme weather events established, the final step is to multiply by the expected cost to restore customers. In Accenture's storm benchmark database, storm restoration is calculated based on total cost per customers out at peak. As illustrated below, while TECO experienced a grand total of about 328,000 customers out from Hurricane Irma, the number of customers out simultaneously was 213,000, as many quick wins are achieved early through switching and the restoration of substation and transmission issues. Approximately two thirds of this peak value are believed to be tree-caused.

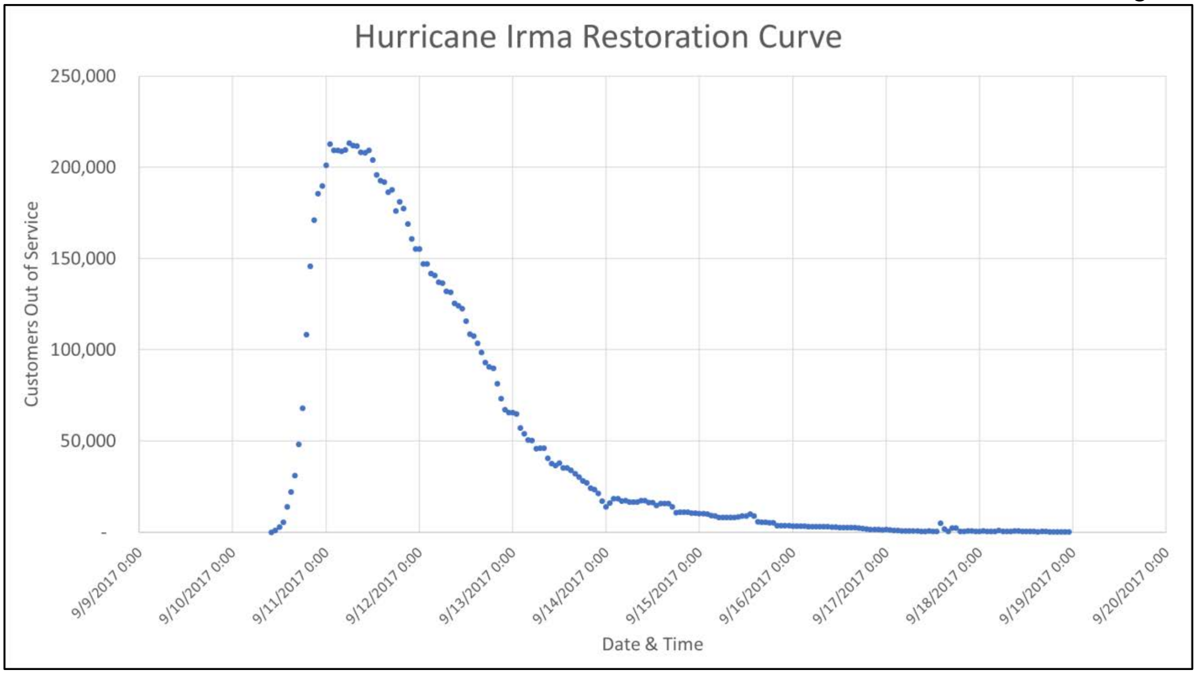



**Figure 6-7: TECO Restoration Curve for Hurricane Irma**

The peak number of customers out forms a more consistent denominator for cost per customer calculations, and in the case of TECO's experience with Irma this worked out to $389 per CI in line, tree, planning, logistics and other costs, which is in line with other Irma experiences in the State. Given the demand pressure on tree and line resources coming out of California's wildfire crisis, and general inflationary pressure, TECO's subject matter experts estimate that costs have risen by ten percent in the past two years, so the same restoration today would cost $424 per CI.

# 7 Work Plan

## 7.1 Baseline Summary

| Work Area | 2020 | | 2021 | | 2022 | | 2023 | |
|---|---|---|---|---|---|---|---|---|
| | Miles | Customers | Miles | Customers | Miles | Customers | Miles | Customers |
| CENTRAL | 260.3 | 43,997 | 262.1 | 44,336 | 260.0 | 51,889 | 260.1 | 52,612 |
| DADE CITY | 93.3 | 4,618 | 80.1 | 2,308 | 107.8 | 5,541 | 90.8 | 3,015 |
| EASTERN | 212.4 | 30,524 | 210.1 | 34,845 | 208.8 | 35,717 | 208.6 | 27,808 |
| PLANT CITY | 311.9 | 16,511 | 308.9 | 16,875 | 309.7 | 22,055 | 311.4 | 12,296 |
| SOUTH HILLSBOROUGH | 178.3 | 16,775 | 176.1 | 26,999 | 181.4 | 14,380 | 184.5 | 18,196 |
| WESTERN | 279.3 | 67,510 | 279.5 | 60,773 | 277.0 | 64,125 | 278.2 | 59,307 |
| WINTER HAVEN | 227.0 | 26,391 | 237.9 | 9,676 | 228.4 | 16,338 | 230.7 | 25,762 |
| Total | 1,562.6 | 206,326 | 1,554.6 | 195,812 | 1573.0 | 210,045 | 1,564.2 | 198,996 |

## 7.2 Supplemental Summary

| Work Area | 2020 | | 2021 | | 2022 | | 2023 | |
|---|---|---|---|---|---|---|---|---|
| | Miles | Customers | Miles | Customers | Miles | Customers | Miles | Customers |
| CENTRAL | 77.9 | 21,357 | 159.1 | 29,226 | 113.5 | 20,418 | 127.1 | 19,538 |
| DADE CITY | 99.9 | 5,208 | 6.2 | 484 | 127.6 | 5,578 | 44.9 | 681 |
| EASTERN | 99.8 | 18,598 | 153.3 | 12,341 | 72.9 | 8,794 | 149.8 | 18,918 |
| PLANT CITY | 76.7 | 9,702 | 25.2 | 2,443 | 202.2 | 8,347 | 31.1 | 3,579 |
| SOUTH HILLSBOROUGH | 15.3 | 2,264 | 20.5 | 2,427 | 20.2 | 3,236 | 138.9 | 28,399 |
| WESTERN | 15.7 | 3,926 | 82.8 | 13,024 | 112.4 | 20,376 | 155.8 | 27,165 |
| WINTER HAVEN | 16.8 | 1,277 | 63.1 | 5,063 | 43.2 | 5,784 | 53.2 | 7,950 |
| Total | 402.3 | 62,332 | 510.2 | 65,008 | 692.0 | 72,533 | 700.8 | 106,230 |

## 7.3 Mid-cycle Summary

| Work Area | 2020 | | 2021 | | 2022 | | 2023 | |
|---|---|---|---|---|---|---|---|---|
| | Miles Inspected | Customers | Miles Inspected | Customers | Miles Inspected | Customers | Miles Inspected | Customers |
| **CENTRAL** | 0.0 | 0 | 48.6 | 17,262 | 36.0 | 9,488 | 176.8 | 25,321 |
| **DADE CITY** | 0.0 | 0 | 2.8 | 1,293 | 5.1 | 904 | 0.0 | 0 |
| **EASTERN** | 0.0 | 0 | 17.3 | 4,730 | 34.5 | 12,007 | 115.3 | 16,234 |
| **PLANT CITY** | 0.0 | 0 | 18.0 | 8,234 | 12.0 | 7,191 | 231.0 | 12,380 |
| **SOUTH HILLSBOROUGH** | 0.0 | 0 | 51.7 | 16,233 | 23.0 | 13,900 | 82.1 | 3,925 |
| **WESTERN** | 0.0 | 0 | 58.8 | 27,318 | 53.3 | 19,073 | 171.2 | 27,479 |
| **WINTER HAVEN** | 0.0 | 0 | 45.9 | 20,663 | 32.1 | 14,565 | 241.5 | 7,779 |
| **Total** | **0.0** | **0** | **243.1** | **95,733** | **196.0** | **77,128** | **1017.9** | **93,118** |

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200067-EI

# TAMPA ELECTRIC’S 2020-2029 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

GERARD R. CHASSE

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**FILED: APRIL 10, 2020**

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**GERARD R. CHASSE**

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**INTRODUCTION**

**Q.** Please state your name, address, occupation and employer.

**A.** My name is Gerard R. Chasse. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the Company") as Vice President, Electric Delivery.

**Q.** Please describe your duties and responsibilities in that position?

**A.** My duties and responsibilities include the oversight of all functions within Tampa Electric's Electric Delivery Department including the planning, engineering, operation, maintenance and restoration of the transmission, distribution and substation systems; operation of the distribution and energy control centers; administration of tariffs and compliance; execution of the Company's Transmission and Distribution ("T&D") strategic solutions including advanced metering infrastructure, outdoor and streetlight LED conversion project, and advanced distribution management system; line clearance activities; warehouse and stores; and fleet and equipment. As it relates to this filing, I am responsible for the development of Tampa Electric's Storm Protection Plan and the safe, timely, and efficient implementation of that Plan.

**Q.** Please describe your educational background and professional experience?

**A.** I received a Bachelor of Science degree in electrical engineering from the University of Maine in 1990 and became a licensed professional engineer in 1996. I have held numerous positions of increasing responsibility in Bangor Hydro Electric and its successor, Emera Maine, including Substation Engineer, Planning Engineer, Substation Operations Supervisor, Manager of Engineering, Manager of Assets, Project Manager for an international transmission line, Vice-President of Operations, Executive Vice-President, and President of Emera Maine from 2010 through 2015. In 2015 and 2016, I was Vice-Chair of the Emera Maine Board. My position was also focused on renewable strategy, grid modernization strategy, and customer strategy for Emera companies from 2015 to 2016 before my current role.

**Q.** What is the purpose of your testimony in this proceeding?

**A.** The purpose of my direct testimony is to present, for Commission review and approval, Tampa Electric’s 2020-2029 Storm Protection Plan. I will introduce the company’s Plan and provide a description of how implementation of the company’s proposed 2020-2029 Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather and enhance reliability by strengthening the company’s infrastructure. I will also offer a description of the company’s service area and describe the process used to develop the Plan, as well as a description of how the Plan’s implementing Programs were selected and prioritized. Finally, I will describe the alternatives to implementation of the Plan that the company considered.

**Q.** Are you sponsoring any exhibits in this proceeding?

**A.** Yes, I am. Exhibit No. GRC-1, entitled, “Tampa Electric’s 2020-2029 Storm Protection Plan”, was prepared under my direction and supervision. This Exhibit details the company’s plans to implement the Storm Protection Plan Rule.

**Q.** Will any other witnesses testify in support of Tampa

Electric's Proposed Storm Protection Plan?

**A.** Yes. Regan B. Haines will testify about six of the eight Programs contained within the Storm Protection Plan. John H. Webster will testify regarding the company's planned Vegetation Management Program and Transmission Access Program. Jason D. De Stigter will testify regarding the methodology to select and prioritize Storm Protection Programs and Projects. Finally, A. Sloan Lewis will testify regarding the estimated annual jurisdictional revenue requirement for the Plan and the estimated rate impacts for each of the first three years of the Plan.

**TAMPA ELECTRIC'S SERVICE AREA**

**Q.** Please describe Tampa Electric's service area and how many customers does the company serve?

**A.** Tampa Electric's Service Area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties. Tampa Electric provides service to 794,953 retail electric customers as of January 1, 2020.

**Q.** Do you have a map of Tampa Electric's service area?

**A.** Yes, a map of Tampa Electric's service area is included below.


**Q.** How many structures does the company's transmission, distribution electrical system have?

**A.** The company has 1,350 miles of overhead facilities, including 25,416 transmission poles. The company's transmission system also includes approximately nine miles of underground facilities. The company's distribution system has 6,300 miles of overhead facilities, including approximately 404,000 poles. The company currently has approximately 5,100 circuit miles of underground facilities. The company currently has 216 substations.

**Q.** In the development of the company's Storm Protection Plan, did Tampa Electric place a higher priority on any areas of the company's service area for hardening or enhancement projects contained in the company's Storm Protection Plan, and if so, please explain the reasoning for this prioritization?

**A.** No. Each of the Programs and each of the Projects are prioritized based on modeled cost/benefit ratios. For example, Tampa Electric used the 1898 & Co. modelling tool to assist in the prioritization of individual Projects and to set the overall Program funding levels for the Distribution Lateral Undergrounding Program. In the initial years of the Program, Projects were selected taking into account modeling results in conjunction with operational and design efficiency which include some level of geographic diversity.

**Q.** In the development of the company's Storm Protection Plan, were there any areas of the company's service area that Tampa Electric determined would be impractical, unfeasible or imprudent for hardening or enhancement projects within the company's Storm Protection Plan, and if so, please explain the reasoning for this reasoning?

**A.** No. There are no areas of the company's service area where it would impractical, unfeasible or imprudent to harden. All components of the transmission and distribution system can be hardened to achieve resiliency benefits.

**PROCESS TO DEVELOP THE 2020-2029 STORM PROTECTION PLAN**

**Q.** Please explain Tampa Electric's systematic approach to achieve the objectives of reducing restoration costs and outage times and enhancing reliability, and how that approach was utilized to develop the company's proposed Storm Protection Plan?

**A.** In response to the new requirement to develop a comprehensive SPP, Tampa Electric evaluated its existing storm hardening activities and searched for potential additions and improvements. The company began by consulting its internal subject-matter experts to identify major causes of storm-related outages and major barriers to restoration following storms. The company then engaged three outside consultants to help it evaluate potential solutions and to assist with estimation of costs and benefits for those solutions. The result is a Plan that includes several newly developed incremental Storm Protection Programs, Projects and activities that resulted from the thorough and comprehensive analysis. These new Programs, as well as the company's legacy Storm Hardening Plan activities, are described more fully in Tampa Electric's Storm Protection Plan. This approach is designed to fully achieve the goals, objectives and requirements of the Florida Legislature and the Commission's Rule.

**Q.** Did Tampa Electric incur any incremental costs in the development of the company's Storm Protection Plan?

**A.** Yes, Tampa Electric hired a program manager in the Energy Delivery Department to facilitate the company's Storm Protection Plan activities. The company also obtained the assistance of three consultants.

**Q.** What role did the three consultants play in the development of the company's Storm Protection Plan?

**A.** The three consultants assisted the company in the development of the Storm Protection Plan in the following three areas:

1. Performing project prioritization and benefits calculations for several of the company's proposed Storm Protection Programs, including: (1) Distribution Lateral Undergrounding; (2) Transmission Asset Upgrades; (3) Substation Extreme Weather Hardening; (4) Distribution Overhead Feeder Hardening; and (5) Transmission Access Enhancements. This prioritization and cost-benefit analysis is described more fully in the Direct Testimony of Jason D. De Stigter.
2. Analyzing the company's current vegetation management activities and developing a methodology for selecting and prioritizing incremental vegetation management activities. This analysis is described more fully in John H. Webster's Direct Testimony.
3. Performing an automation analysis for the 22 prioritized distribution circuits for the Overhead Feeder Hardening Program for 2020-2022.

**Q.** Would you explain why the company chose to obtain the consulting services for assistance with the development of the Storm Protection Plan?

**A.** The company chose to obtain consulting services for assistance with the development of the Storm Protection Plan for a number of reasons including: (1) it did not have the incremental resources available to continue its existing operations and meet the filing requirements required by the Rule; and (2) it did not have the sophisticated modeling tools necessary to perform a thorough and detailed benefits and prioritization analysis for the Vegetation Management Program or the other five Programs listed above.

**TAMPA ELECTRIC’S 2020-2029 STORM PROTECTION PLAN**

**Q.** Would you describe Tampa Electric’s 2020-2029 Storm Protection Plan?

**A.** Tampa Electric’s Storm Protection Plan is designed with the primary objective of enhancing the resiliency and reliability of its transmission and distribution systems during extreme weather events. Over the next ten years, Tampa Electric will build upon the success of its existing Storm Hardening Plan to materially improve resiliency through targeted investments in the following

Programs: (1) Distribution Lateral Undergrounding; (2)Vegetation Management; (3) Transmission Asset Upgrades; (4)Substation Extreme Weather Hardening; (5) Distribution Overhead Feeder Hardening; (6) Transmission Access Enhancement; (7) Infrastructure Inspections; and (8) Legacy Storm Hardening Initiatives. These Programs will minimize the impact of severe weather by hardening Tampa Electric's infrastructure.

**Q.** Will Tampa Electric's Storm Protection Plan further the objectives of Section 366.96 of the Florida Statutes?

**A.** Yes. We developed a Storm Protection Plan based on a rigorous analysis of possible methods to achieve the goals of Section 366.96 of the Florida Statutes. The goal of our analysis was to identify those activities that deliver the greatest storm resiliency and reliability benefits for the lowest cost. We believe that the company's Plan will deliver significant resiliency benefits, reliability benefits and reduced outage times to our customers in a cost-effective manner.

**Q.** How is Tampa Electric Company's Plan designed to deliver those benefits?

**A.** Tampa Electric's Storm Protection Plan is comprised of four new and four currently ongoing Storm Protection Programs. Four of these Storm Protection Programs are comprised of individual Projects. In addition, the company plans to incorporate existing activities from its 2019-2021 Storm Hardening Plan into the new 2020-2029 Storm Protection Plan. This will result in overall regulatory and business efficiency in managing one program rather than two.

**Q.** Would you describe the Programs in Tampa Electric's Storm Protection Plan?

**A.** Tampa Electric separated the three main requirements of the Storm Protection Statute – overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management – into eight distinct Programs. The Programs are as follows:

- **Distribution Lateral Undergrounding**
- **Vegetation Management**
- **Transmission Asset Upgrades**
- **Substation Extreme Weather Hardening**
- **Distribution Overhead Feeder Hardening**
- **Transmission Access Enhancement**

- **Infrastructure Inspections**
- **Legacy Storm Hardening Initiatives**

**Q.** Would you provide a brief description of each of the eight supporting Storm Protection Programs?

**A.** Yes, a brief description of each of the supporting Storm Protection Programs is below:

**Distribution Lateral Undergrounding:** Tampa Electric has approximately 4,900 miles of overhead lateral distribution lines. Tampa Electric does not currently have an organization or program for undergrounding laterals. Accordingly, the company will spend 2020 building an organization, developing and refining processes and acquiring formal arrangements with external resources to build and sustain this Program for the duration of the SPP. The company is targeting 10 miles of overhead to underground conversion in 2020 and targeting 100 – 110 miles of overhead to underground conversion from the start of the program in 2020 through the end of 2021. Beginning in 2022, the company plans to underground 100 miles or more annually.

The company and its consultant, 1898 & Co., determined the priority of these laterals through use of a robust modeling tool. The primary factor in prioritizing undergrounding Projects is reliability performance during extreme weather events. To illustrate, approximately 55 percent of all outages are caused by 30 percent of the company's lateral distribution lines. The prioritization method also gives due regard to the distribution of Projects across Tampa Electric's service area. All targeted laterals served by the same feeder will be undergrounded at once for efficiency in construction and in future storm response.

**Vegetation Management:** The company's Vegetation Management Program is comprised of four components: (1) existing trim cycles; (2) supplemental distribution trimming; (3) inspection-based mid-cycle trimming; and (4) reclamation of the 69kV transmission system.

The company currently implements a four-year effective distribution vegetation management cycle. Over a four-year period, 100 percent of the approximately 6,300 miles of distance of overhead lines are targeted to be cleared with due regard to circuit performance. Additionally, over the past three years, approximately $1.7M per year of reactionary trim has been performed. Reactionary vegetation management is typically driven by customer requests or degraded circuit reliability performance, often in the latter half of a circuit's trim cycle due to specific species demonstrating faster growth cycles.

Additionally, for transmission circuits above 200kV, the company complies with FERC standards and employs strict two- and three-year cycles for transmission circuits operating at voltages below 200kV.

As part of its Storm Protection Plan, the company proposes three additional vegetation management initiatives with the purpose of enhancing its current cycle-based program specifically to increase resiliency. Those initiatives include supplemental distribution circuit vegetation management, inspection-based mid-cycle distribution vegetation management, and 69kV vegetation management reclamation work. Detailed modeling by the company's consultant, Accenture, demonstrates that an additional 700 miles of supplemental distribution trimming would achieve the greatest ratio of benefits to costs under extreme weather conditions. The mid-cycle vegetation management initiative is inspection-based and designed to eliminate trees and vegetation that pose a hazard to the distribution lines but can't effectively be eliminated within the four-year cycle. Finally, the 69kV reclamation project is designed to increase access to difficult-to-reach areas of the company's high voltage transmission system. Accessibility to transmission in rights of way is an important factor in the speed of restoration and significantly enhances overall system resiliency.

**Transmission Asset Upgrades:** Approximately 20 percent of Tampa Electric's 25,400 transmission poles are wood pole structures. This Program consists of the proactive replacement of all remaining wood pole structures on the company's transmission system. The company proposes to accelerate the replacement of those structures to non-wood material, typically steel or concrete, to enhance the resiliency of the transmission system during extreme weather events.

Tampa Electric utilized 1898 & Co.'s resilience-based modeling to develop the initial prioritization of Projects based on historical performance relative to criticality of the transmission line, reduction of customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. Technical and operational constraints like access and long-lead time permits were also accounted for in the development of priority.

This Program offers a high level of benefits, yet these benefits are highly dependent on the frequency of extreme weather events. The CMI reduction benefit for the Transmission Asset Upgrades Program is approximately 29 percent while the resulting restoration cost reduction benefit is approximately 90 percent after an extreme weather condition.

**Substation Extreme Weather Hardening:** This Program is designed to increase the resiliency of flood-prone critical substation equipment. It may include the installation of extreme weather protection barriers; installation of flood or storm surge prevention barriers; additions, modifications or relocation of substation equipment; modification to the designs of the company's substations; or other approaches identified to protect against extreme weather damage in or around the company's substations. Tampa Electric has approximately 59 substations that are at risk in the event of hurricane-related storm surge. The company plans to commission a study to assess the vulnerability of the top 20 of these

59 substations, which will result in a recommendation for the prioritization of future substation Projects and a recommendation for the tactics used to mitigate their vulnerabilities.

**Distribution Overhead Feeder Hardening:** The performance of three phase feeders is critical during extreme weather events. Tampa Electric’s Distribution Overhead Feeder Hardening Program will include enhancements designed to increase resiliency, reliability, and flexibility of its three phase feeders including Distribution Feeder Strengthening and Distribution Feeder Sectionalizing and Automation.

Distribution Feeder Strengthening will incorporate design standards changes focused on the physical strength of the distribution infrastructure. The company will transition to using minimum Class 2 poles for all feeders and 3-phase laterals providing for longer life and increased overall strength.

Distribution Feeder Sectionalizing and Automation will enable the transfer of load to adjacent unfaulted feeders through the addition of new equipment such as breakers, reclosers, sectionalizers, sensors, relays, and communication equipment in addition to increased feeder capacity in some locations. Feeders will be divided into sections feeding smaller numbers of customers so that when faults occur on a feeder section, that section can automatically isolate from the remainder of the healthy system. These design and standards changes will increase the overall resiliency of the company's feeder distribution system to withstand all ranges of extreme weather events.

**Transmission Access Enhancement:** Ready access to the company's approximately 1,350 miles of transmission facilities is critical to the efficient and timely restoration of its transmission system under all types of conditions, including blue sky and extreme weather events. This Program is designed to ensure effective access to those facilities with the addition or enhancement of roads and rights of way. Access roads also enable more efficient maintenance of the rights of way, including vegetation management in and along those corridors. Adequate access roads eliminate the need for costly and time-consuming installments of matting to provide temporary access to critical infrastructure. This Program also includes the design and construction of 17 access bridges. Access bridges are critical for moving heavy equipment in and along transmission corridors, enabling efficient restoration, maintenance and repair of transmission structures.

**Infrastructure Inspections:** Infrastructure inspections are a foundational element of an asset management program. A clear understanding of the condition of distribution, substation, and transmission assets is a critical piece of asset performance under any conditions. Tampa Electric's Infrastructure Inspection Program is a comprehensive inspection program that combines the legacy Storm Hardening Plan initiatives of: Wood Pole Inspections, Transmission Structure Inspections, and the Joint Use Pole Attachment Audit.

The company's inspection programs drive decisions on whether to replace, repair or restore its wood pole transmission, distribution, and substation infrastructure as well as the company's understanding of whether unauthorized attachments may have overloaded that infrastructure. The company believes that these are core initiatives with demonstrated value. As a result, the company has not prepared a new cost-benefit analysis for these activities. These are existing programs and the company proposes to continue them at approximately historical spending levels.

**Legacy Storm Hardening Initiatives:** The final category of storm protection activities consists of those legacy Storm Hardening Plan Initiatives that are ongoing and well-established, and for which the company does not propose any specific Storm Protection Projects at this time. Tampa Electric will continue these activities because the company believes they are necessary utility activities, conform to good utility practice, and continue to offer the storm resiliency benefits identified by previous Commission orders which required the company to perform these activities. These activities are still mandated by the Commission and the associated initiatives are all integrated into the company’s ongoing operations. Historically, Tampa Electric has not performed a formal cost benefit analysis for these activities because they were mandated by the Commission. Most notable of these programs is Tampa Electric’s distribution pole replacement initiative. It starts with the company’s wood pole inspections and includes designing and constructing distribution facilities that meet or exceed the company’s current design criteria for the distribution system. The company will continue to appropriately address all poles identified through its Infrastructure Inspection Program and in accordance with the National Electric Safety Code for wood pole strength requirements.

Given that this is a reactive activity (poles are replaced or restored only when they fail an inspection), Tampa Electric concluded that it was not practical or feasible to identify specific distribution pole replacement Storm Protection Projects.

**Q.** Please explain how the implementation of the company's proposed Storm Protection Plan will strengthen the company's infrastructure to withstand extreme weather conditions through overhead hardening of electrical transmission and distribution facilities as required by Rule 25-6.030(3)(a)?

**A.** Implementation of the company's Transmission Asset Upgrades and Distribution Overhead Feeder Hardening Programs will strengthen the company's infrastructure to withstand extreme weather conditions through overhead hardening of electrical transmission and distribution facilities. These Programs include transmission pole upgrades from wood to primarily steel or concrete, and the overhead hardening of distribution facilities through both feeder strengthening and sectionalization and automation. Increasing the strength of overhead facilities increases the ability of the company’s poles, conductors and fixtures to resist wind loading during extreme weather events as well as loading from vegetation contacts. Eliminating infrastructure failures significantly reduces outages and time to restore outages. Automatic switching during storm events is designed to minimize outage impact to approximately 400 or fewer customers depending on the characteristics of the circuit. Outage locations are sensed, isolated, and adjacent unfaulted sections of feeders can be reenergized.

**Q.** Please explain how the implementation of the company’s proposed Storm Protection Plan will strengthen the company’s infrastructure to withstand extreme weather conditions through undergrounding certain portions of electrical distribution lines as required by Rule 25-6.030(3)(a)?

**A.** Implementation of the company’s Distribution Lateral Undergrounding Program will strengthen the company’s infrastructure through undergrounding portions of its lateral distribution lines. Underground laterals are shielded from many of the potential harmful effects of extreme weather events resulting in a number of significant benefits to customers. Indeed, metrics from past extreme weather events clearly show that underground systems prove to be much stronger and more resilient. The Program will reduce the number and severity of customer outages during extreme weather events, reduce the amount of system damage during extreme weather, reduce the material and manpower resources needed to respond to extreme weather events, reduce the number of customer complaints from the reduction in outages during extreme weather events, and reduce restoration costs following extreme weather events.

**Q.** Please explain how the implementation of the company's proposed Storm Protection Plan will strengthen the company's infrastructure to withstand extreme weather conditions through vegetation management as required by Rule 25-6.030(3)(a)?

**A.** The implementation of the company's proposed Vegetation Management Program will strengthen the company's infrastructure to withstand extreme weather conditions through vegetation management initiatives. Trees are the leading cause of outages both during extreme weather events and normal operations. Three new vegetation management initiatives in addition to the company's existing cycles will reduce the potential for vegetation to come into contact with the company's distribution and transmission lines during extreme weather events.

**Q.** Please explain how the implementation of the company's proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions as required by Rule 25-6.030(3)(b)?

**A.** The implementation of the company's proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions through a comprehensive approach using eight specific Programs. The combination of five of the first six Programs were modeled, assessed and optimized using a sophisticated storm resilience model employed by the company's consultant 1899 & Co. The incremental vegetation management initiatives were developed through detailed analysis using Accenture's TTM model. The proposed Programs also underwent additional analysis performed by Tampa Electric. These analyses demonstrate there are significant benefits associated with these Programs including reduced restoration costs, reduced outages, and reduced restoration times. Further Program benefits will accrue in day-to-day operations.

**Q.** Please explain how the implementation of the company's proposed Storm Protection Plan will improve overall service reliability and customer service as required by Rule 25-6.030(3)(b)?

**A.** The implementation of the company's proposed Storm Protection Plan will improve overall service reliability and customer service. Each of the eight Storm Protection Plan Programs will not only meet the storm resiliency goals of the Rule and the statute, but will also have significant reliability benefits during blue sky operations. The Plan will result in reduced outages, both momentary and sustained, and reduced restoration times resulting in reduced operating and capital costs.

**ESTIMATED COSTS OF STORM PROTECTION PLAN**

**Q.** Did the company prepare an estimate of the annual jurisdictional revenue requirements for each year of the proposed Plan?

**A.** Yes. The estimated annual jurisdictional review requirements for each year of the proposed Storm Protection Plan are included in Section 7 of the company’s Storm Protection Plan. A full explanation of the detail of these jurisdictional revenue requirements and how they were calculated for each year of the proposed storm protection plan is included as Exhibit No. ASL-1, Document No. 1 within A. Sloan Lewis’s direct testimony in this proceeding.

**ESTIMATED RATE IMPACTS OF STORM PROTECTION PLAN**

**Q.** Did the company prepare an estimate of rate impacts for each of the first three years of the proposed storm protection plan for a typical residential, commercial and industrial Tampa Electric customer?

**A.** Yes. The estimated rate impacts for each of the first three years of the proposed Storm Protection Plan for a typical residential, commercial and industrial Tampa Electric customer are included in the table below. A full detail explanation of these rate impacts and how they were calculated for each of the first three years of the proposed Storm Protection Plan is included in A. Sloan Lewis’s direct testimony in this proceeding.

| | Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent) | | | |
|---|---|---|---|---|
| | Customer Class | | | |
| | Residential 1000 kWh | Residential 1250 kWh | Commercial 1 MW 60 percent Load Factor | Industrial 10 MW 60 percent Load Factor |
| 2020 | 1.50 | 1.48 | 1.44 | 0.55 |
| 2021 | 2.22 | 2.21 | 2.14 | 0.84 |
| 2022 | 3.09 | 3.06 | 2.98 | 1.13 |
| 2023 | 4.12 | 4.07 | 3.95 | 1.46 |

**IMPLEMENTATION ALTERNATIVES**

**Q.** Did the company consider any implementation alternatives that would mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan?

**A.** Yes. The company considered and quickly rejected an alternative that involved no incremental storm protection activities. This alternative was quickly dismissed because it does not achieve the objectives of the statute, which are to further reduce restoration costs and outage times associated with extreme weather and to enhance reliability. The company engaged Accenture to evaluate several initiatives to enhance the company's vegetation management plans and performance. As part of this analysis, several increments of activity and spending were evaluated. The company selected the option that yielded the most customer benefits. Tampa Electric also worked with 1898 & Co. to perform a budget analysis, which demonstrated significantly increasing levels of net benefit from the $250 million to $1.5 billion budget scenarios. The company's planned investment level is at the optimal point before diminishing returns. Tampa Electric also considered and rejected some capital programs and projects including undergrounding distribution feeders, proactively upgrading wood distribution poles, and purchasing temporary transmission access solutions such as matting.

**ADHERENCE TO F.A.C. RULES AND STATUTORY REQUIREMENTS**

**Q.** Does the process utilized by Tampa Electric to establish its proposed Storm Protection Plan for the 2020-2029 period address the requirements of Rule 25-6.030, F.A.C.?

**A.** Yes. Under Rule 25-6.030(3), F.A.C., a utility's Storm Protection Plan must contain several specific categories of information. The table below shows where each category of information is located within the company's Proposed Storm Protection Plan.

| Tampa Electric's 2020-2029 Storm Protection Plan Adherence to Rule 25-6.030 F.A.C. | |
|---|---|
| **Required Contents of Plan** | **Section of the Storm PP** |
| 25-6.030(3)(a)-(b) | Section 3 - SPP Overview |
| 25-6.030(3)(c) | Section 1 - Tampa Electric's Service Area |
| 25-6.030(3)(d)1-4 | Section 6 – Storm Protection Programs |
| 25-6.030(3)(d)5 | Section 3 – SPP Overview |
| 25-6.030(3)(e) | Section 6 – Storm Protection Programs |
| 25-6.030(3)(f) | Section 6.2 – Vegetation Management |
| 25-6.030(3)(g) | Section 7 – Projected Costs and Benefits |
| 25-6.030(3)(h) | Section 8 – Estimated Rate Impacts |
| 25-6.030(3)(i) | Section 9 – Alternatives and Considerations |
| 25-6.030(3)(j) | N/A (optional) |

**Q.** Does Tampa Electric's Storm Protection Plan further the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability set out in Section 366.96(3) of the Florida Statutes?

**A.** Yes. As my testimony demonstrates, the company's Storm Protection Plan will achieve these objectives by hardening the company's infrastructure and making it more resilient and reliable during extreme weather events.

**CONCLUSIONS:**

**Q.** Please summarize your direct testimony.

**A.** My testimony and the direct testimony of Regan B. Haines, A. Sloan Lewis, John H. Webster, and Jason D. DeStigter and the accompanying exhibits present and support Tampa Electric's proposed 2020-2029 Storm Protection Plan. This Plan was developed in a manner consistent with the requirements of Section 366.96, Florida Statutes and the implementing Rule 25-6.030, F.A.C., adopted by the Commission.

**Q.** Should Tampa Electric's proposed 2020-2029 Storm Protection Plan be approved?

**A.** Yes. Tampa Electric's proposed 2020-2029 Storm Protection Plan should be approved. The Plan contains all of the required contents set out in Rule 25-6.030, F.A.C. The Plan will also build on the benefits the company achieved through the prior Storm Hardening Plans and initiatives that were established by this Commission in 2007. Finally, the Plan will accelerate the company's existing hardening efforts to achieve the objectives of Section 366.96(3) of the Florida Statutes by strengthening the company's infrastructure to withstand extreme weather conditions, reducing restoration costs and outage times, and by improving overall reliability and customer satisfaction.

**Q.** Does this conclude your testimony?

**A.** Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200067-EI
WITNESS: CHASSE

# EXHIBIT

# OF

# GERARD R CHASSE

**34**

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**EXHIBIT NO. GRC-1**
**WITNESS: CHASSE**
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**FILED: 04/10/2020**

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# Tampa Electric's 2020–2029 Storm Protection Plan

**Filed: April 10, 2020**

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# Tampa Electric's 2020-2029 Storm Protection Plan Summary

Tampa Electric's 2020-2029 Storm Protection Plan describes the company's comprehensive approach to protect and strengthen its electric utility infrastructure to withstand extreme weather conditions as well as to reduce restoration costs and outage times in a prudent, practical and cost-effective manner. Protecting and strengthening Tampa Electric's transmission and distribution electric utility infrastructure against extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.

Tampa Electric's 2020-2029 Storm Protection Plan will be its first ten-year protection plan filed in response to Rule 25-6.030, Storm Protection Plan. That Rule, which became effective on February 18, 2020, requires utilities to file storm protection plans. Tampa Electric has developed this Plan to comply with the Rule. This Plan contains a description of the company's Storm Protection Programs, the specific supporting Projects to these Programs and required detail as prescribed by Rule 25-6.030. This Plan also incorporates the continuation of legacy Storm Hardening Plan Initiatives that have been in place since 2006 and wood pole inspections.

# Table of Contents

## 1 Tampa Electric's Service Area:

Tampa Electric's Service Area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties as shown in the figure below. The company's service area is divided into seven "service areas" for operational and administrative purposes. Tampa Electric provides service to 794,953 retail electric customers as of January 1, 2020.


Tampa Electric's transmission system consists of nearly 1,350 circuit miles of overhead facilities, including 25,416 transmission poles and structures. The company's transmission system also includes approximately nine circuit miles of underground facilities. The company's distribution system consists of approximately 6,250 circuit miles of overhead facilities and 414,000 poles. The company currently has approximately 5,550 circuit miles of underground distribution facilities. The company currently has 216 substations. Tampa Electric also has approximately 322,000 authorized joint user attachments on the company's transmission and distribution poles.

Tampa Electric developed the proposed 2020-2029 Storm Protection Plan and its supporting Programs and initiatives by examining the entire company's service area for the most cost-effective enhancement opportunities. Tampa Electric did not exclude any area of the company's existing transmission and distribution facilities for consideration for enhancement due to feasibility, reasonableness or practicality concerns.

## 2 References:

The following resources are referenced in this Plan:

a) 2017 National Electrical Safety Code
b) National Hurricane Center Database
c) Florida State Building Code
d) Hillsborough County Wind Maps
e) Tampa Electric's prior Storm Implementation Plans
f) Tampa Electric's Distribution Engineering Technical Manual
g) Tampa Electric's Standard Electrical Service Requirements
h) Tampa Electric's General Rules and Specifications-Overhead
i) Tampa Electric's General Rules and Specifications-Underground
j) Tampa Electric's Approved Materials Catalog
k) Hillsborough County Flood Hazard Maps

## 3 Storm Protection Plan Overview

Tampa Electric's Storm Protection Plan ("Plan" or "SPP") sets out a systematic and comprehensive approach to storm protection focused on those Programs and Projects that provide the highest level of reliability and resiliency benefits for the lowest relative cost. The company believes that these activities will achieve the Florida Legislature's goals of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability" in a cost-efficient manner.

In 2006 and 2007, the Florida Public Service Commission ("FPSC" or "Commission") issued two orders related to storm hardening and enacted Rule 25-6.0342, Florida Administrative Code ("F.A.C."), which requires utilities to prepare and submit a "Storm Hardening Plan" every three years. Through these actions, the Commission directed utilities to complete specific hardening activities, such as equipment inspections, post-storm data collection, and vegetation management cycles. In the years since, Tampa Electric Company has consistently performed these required activities and delivered significant storm resiliency benefits to customers.

In 2019, the Florida Legislature enacted a new law requiring utilities to prepare a "transmission and distribution storm protection plan." § 366.96(3), Fla. Stat. The statute requires utilities to develop a "transmission and distribution storm protection plan" setting out a "systematic approach" to reducing outage times and restoration costs associated with extreme weather and enhancing reliability. § 366.96(3), Fla. Stat. The Florida Legislature clearly intended that utilities should examine all options for achieving those goals, even those that go beyond the Commission's existing list of required Storm Hardening Plan activities.

In response to the new requirement to develop a comprehensive

SPP, Tampa Electric evaluated its existing Storm Hardening Plan activities and searched for potential additions and improvements. The company began by consulting its internal subject-matter experts to identify major causes of storm-related outages and major barriers to restoration following storms. The company then engaged three outside consultants to help it evaluate potential solutions and to assist with estimation of costs and benefits for those solutions.

First, Tampa Electric engaged Accenture, LLP ("Accenture") to evaluate its existing vegetation management ("VM") activities and determine what types of incremental vegetation trimming would reduce storm-related outage times and restoration costs. Tampa Electric's Line Clearance Department and Accenture developed and finalized the SPP spending plan described in the VM section. Spending levels were evaluated for each of the initiatives, using multiple activities, and ultimately resulted in the proposed list of VM initiatives and spending levels. A complete copy of Tampa Electric's Vegetation Management Storm Protection Program Analytic Support Report is included as Appendix "G".

Second, Tampa Electric engaged 1898 & Co. to perform Project prioritization and benefits calculations for several of the company's proposed Storm Protection Programs, including:

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

Tampa Electric and 1898 & Co. used a resilience-based planning approach to identify hardening Projects and prioritize investment in the transmission and distribution (T&D) system using 1898 & Co's Storm Resilience Model. The Storm Resilience

Model consistently models the benefits of all potential hardening Projects for an accurate comparison across the system. The resilience-based planning approach calculates the benefits of storm hardening Projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, Project, and Program level. The results of the Storm Resilience Model are:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as Customer Minutes of Interruption("CMI")

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefits. A detailed overview of the Storm Resilience Model used to calculate the Project benefit and prioritize Projects is included in Tampa Electric's Storm Protection Plan Resilience Benefits Report in Appendix "F".

The storms database includes the future 'universe' of potential storm events to impact the company's service area. 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. Each storm scenario was 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") was based on the vegetation density around each conductor asset, the age and condition of the asset base, and the wind zone in which the asset is located. The Storm Impact Model also estimated the restoration costs and CMI for each of the Projects. Finally, the Storm Impact Model calculated the benefit in decreased restoration costs and CMI if that Project is hardened per the company's hardening standards. The CMI benefit was monetized using the DOE's Interruption Cost Estimator ("ICE") for Project prioritization purposes.

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 employed stochastic modeling, or Monte Carlo Simulation, to randomly trigger the types of storm events to impact Tampa Electric’s service area over the next 50 years. The probability of each storm scenario was 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 were evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

The Budget Optimization and Project Scheduling model prioritized the Projects based on the highest resilience benefit cost ratio. The model prioritized each Project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the Project cost. This was done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporated Tampa Electric’s technical and operational (transmission outages) in scheduling the Projects.

This 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 receive the largest return on investment.

Early iterations of the modeling tool allowed the company to understand the Storm Protection Programs and the benefits that could be expected. In addition, Tampa Electric personnel factored the legacy Program Storm Hardening Plan Initiatives into these evaluations. Also, real-world considerations were included that examined practical realities of multi-year implementation, such as growing and sustaining an external workforce, scheduled outages, coordination of efforts and the ability to execute timely. Together, these aspects were used alongside the modeling tool to develop the final set of Programs, Program funding and ultimately individual Project selection. A complete copy of Tampa Electric’s Storm Protection Plan Resilience Benefits Report is included as Appendix “F”.

Third, Tampa Electric engaged Power Engineers, Incorporated, to perform an automation analysis for the (22) prioritized distribution circuits for the 2020-2022 Overhead Feeder Hardening Program. The analysis determined the number and placement of reclosers, conductor upgrades, substation transformer capacity increases, relay upgrades and in some instances circuit extensions, to meet the company’s criteria to reduce customer exposure, impact and count for unplanned outages. These proposed system enhancements were also used as input to the broader 1898 & Co. analysis described below.

Finally, the company used the analyses provided by these consultants as a basis for establishing the spending levels in the proposed 2020-2029 SPP. This information was used in conjunction with technical and operational constraints to select Storm Protection Programs, Program funding levels and Project selection and prioritization. The company’s 2020-2029 SPP is thus comprised of both the company’s legacy Storm Hardening Plan activities, as well as those incremental activities that emerged from this rigorous analysis process to fully meet the goals, objectives and requirements of the Florida Legislature and the Commission.

# 4 Experience with Major Storm Events

Tampa Electric has significant experience preparing for, responding to, performing restoration and assisting other utilities in recovery from major storm events. The company's response to major storms that have impacted Tampa Electric's service area and the mutual assistance trips to assist other utilities have given Tampa Electric's restoration crews opportunities to gain valuable restoration knowledge and experience in restoring service after a major storm event. This knowledge includes the importance of conducting a damage assessment immediately after the storm has passed and providing customers with an accurate Estimated Time of Restoration ("ETR"). In addition to this experience, Hurricanes Matthew (2016), Hermine (2016), Harvey (2017), Irma (2017), Maria (2017) and Michael (2018) further exposed how vulnerable coastal regions are to the significant damaging effects of storm surge and the significant effort required to restore a system that has been impacted by coastal flooding. These experiences and industry best practices were discussed, analyzed and used to improve Tampa Electric's storm response plan.

Table 1 below provides the details of named storms affecting Tampa Electric's service area since 1960. The data is from the National Hurricane Center database.

**Table 1: Named Storms Affecting Tampa Electric Service Area since 1960**

| Year | Storm Name | Size [1] | Wind Speed [2] |
|---|---|---|---|
| 1960 | Donna | Cat 3 | 115 |
| 1995 | Erin | TS | 57 |
| 2004 | Charley | Cat 2 | 86 |
| 2004 | Francis | Cat 1 | 63 |
| 2004 | Jeanne | Cat 1 | 63 |
| 2005 | Dennis | TS | 43 |

| | | | |
|---|---|---|---|
| 2005 | Wilma | TS | 44 |
| 2006 | Alberto | TS | 45 |
| 2007 | Barry | TS | 31 |
| 2012 | Debby | TS | 53 |
| 2012 | Isaac | TS | 36 |
| 2013 | Andrea | TS | 47 |
| 2015 | Erika | TS | <39 |
| 2016 | Colin | TS | <39 |
| 2016 | Hermine | Cat 1 | 37 |
| 2016 | Matthew | TS | 20 |
| 2017 | Emily | TS | <39 |
| 2017 | Irma | Cat 1 | 90 |
| 2018 | Alberto | TS | 29 |
| 2019 | Nestor | TS | 26 |

Note 1: Maximum category when the storm passed through the Tampa Electric service area.

Note 2: Maximum sustained surface wind speed measured in miles per hour ("mph") when the storm passed through the Tampa Electric service area.

# 5 Construction Standards, Policies, Practices and Procedures

Tampa Electric's existing construction standards, policies, practices and procedures were developed over time to promote the ability of the company to provide safe and reliable electric service at reasonable rates. The company has included these standards, policies, practices and procedures in each of the three-year Storm Hardening Plans filed with and approved by the FPSC and is including these in this Plan document as important background and context for the Program elements of its Storm Protection Plan. The company will continue to evaluate and enhance its standards, policies, practices and procedures to incorporate new storm hardening and resiliency techniques.

## 5.1 National Electrical Safety Code Compliance

Tampa Electric's construction standards and policies meet or exceed all minimum National Electric Safety Code ("NESC") Rule requirements.

## 5.2 Wind Loading Standards

NESC Rule 250, which addresses pole loading requirements in the United States, is divided into three loading districts; Heavy, Medium and Light (see Figure 2 below). Tampa Electric's service area is in the Light loading district, which assumes no ice buildup and a wind pressure rating of nine pounds per square foot. The nine-pound wind corresponds to wind speeds of approximately 60 mph. The Light loading district wind speed corresponds to a wind pressure of more than twice that in the Heavy or Medium districts due to the strong (non-linear) dependence of the wind force on wind speed (i.e., the wind pressure is proportional to the square of the wind speed). Another part of the NESC Rule 250 requires safety loading factors to be applied to the calculated wind forces to provide a conservative margin of safety when selecting appropriate pole sizes. A safety loading factor of 2.06:1 is applied to Grade C construction and 3.85:1 is applied to Grade B construction. The effective wind speed of Grade B new construction is approximately 116 mph. According to the NESC, Grade B wind loading criteria must be applied when constructing facilities less than 60 feet in height when crossing railroads, bridges and highways.

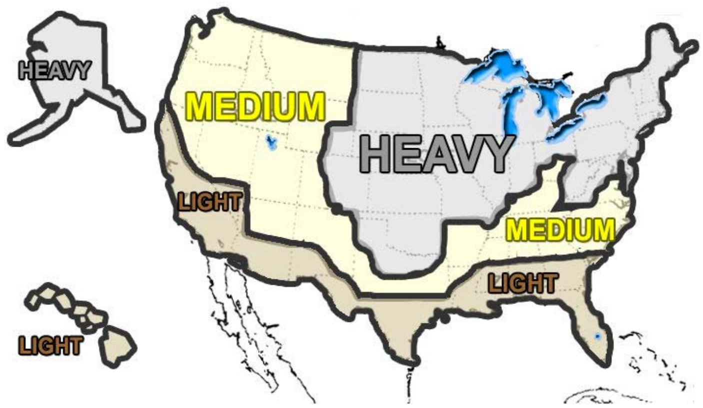



Figure 2: NESC General loading map of United States with respect to loading of overhead lines.

### 5.2.1 Extreme Wind Loading Criteria

The NESC also specifies an extreme wind pole loading criterion for all facilities constructed that are 60 feet in height or greater. The NESC provides a wind loading map that indicates the wind speed criteria for each area of the country. These same criteria and regional boundaries, developed by the American Society of Civil Engineers ("ASCE"), are used by the state of Florida and Hillsborough County for building code requirements. Tampa Electric's service territory is divided into two wind regions (see Figure 3 below). The western half is in the 120-mph zone and the eastern half is in the 110-mph zone.

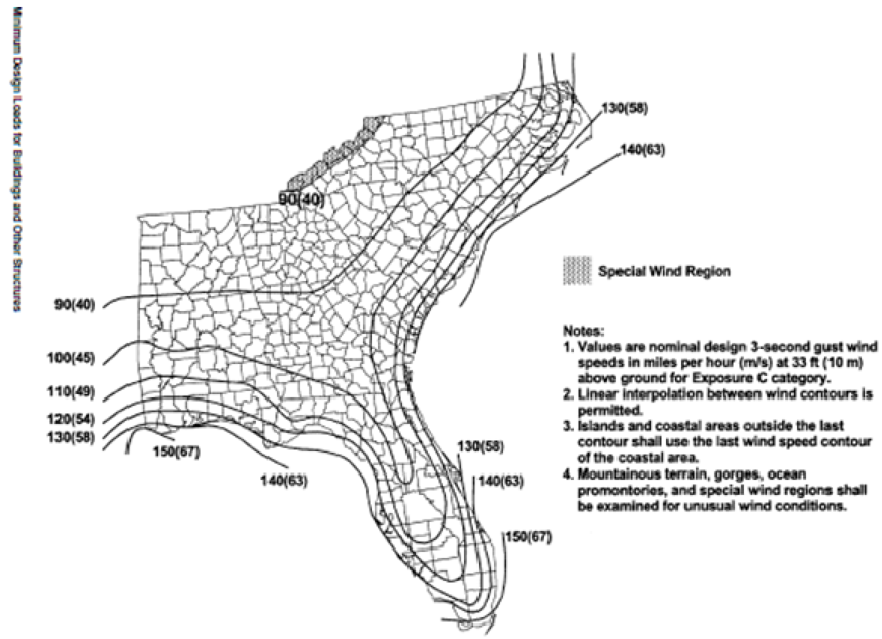



Figure 3: ASCE 74-10 Eastern Gulf of Mexico and Southeastern U.S. Hurricane Coastline

### 5.3 Distribution

This section of the Plan builds upon the design philosophy discussed above and provides an overview of the design criteria, construction standards and practices applicable to all new distribution facilities. This section also presents a broad discussion of the distribution materials and structure types the company uses.

Tampa Electric has developed and maintains a Distribution Engineering Technical Manual (“DETM”) which provides corporate and field personnel the policies, procedures and technical data related to the design of distribution facilities owned and operated by the company. Information contained in this manual along with the Standard Electrical Service Requirements (“SERS”), General Rules and Specification – Overhead (“GR&S-

OH”), General Rules and Specification – Underground (“GR&S-UG”) and the Approved Material Catalog (“AMC”) provide guidelines for designing, constructing and maintaining Tampa Electric’s distribution system.

**5.3.1 Design Philosophy**

The basis of Tampa Electric’s construction standards, policies, practices and procedures has been the NESC Grade B-Light since the 1980’s. All new overhead main feeder lines will be constructed to meet the NESC Extreme Wind loading criteria for our area. All new lateral lines will be constructed underground if doing so will reduce storm restoration costs and outage times. From this foundation, it supports the company’s philosophy of providing safe, reliable and cost-effective service to its customers.

**5.3.2 Overhead System**

**5.3.2.1 Voltage**

Tampa Electric’s primary distribution system operates at a uniform 13.2 kilovolts (“kV”) at three-phase. Secondary voltage is provided in conjunction with the primary distribution system.

**5.3.2.2 Clearances**

Primary voltage conductors are in the power space on the pole that is the upper most portion of the pole as defined by the NESC. Secondary and service conductors along with the neutral are located approximately six feet lower than the primary conductors. Joint use attachers are in the communication space on the pole which is at a minimum 40 inches below the neutral cable or Tampa Electric’s communication cable.

**5.3.2.3 Pole Loading**

The company’s design and construction standard for all new construction, major planned work, expansions, rebuilds and relocations on the overhead distribution system will follow the

NESC construction Grade B criteria with the NESC Extreme Wind loading criteria applied to all Feeder main lines. As described above, the safety factors considered in the NESC construction Grade B criteria provide for a system that is 87 percent stronger than the NESC construction Grade C criteria which results in a more robust design. The company's experience has shown that this design provides safe, reliable and cost-effective service. This standard exceeds the minimum requirement of the NESC, which requires distribution poles to be designed to construction Grade C. While the NESC requirements related to extreme wind conditions apply to only structures over 60 feet in height and rarely apply to distribution structures, they will be used as a new design and construction standard for all new feeder construction and priority feeder hardening.

#### 5.3.2.4 Materials

There are several types of poles that are used for distribution structures. Tampa Electric's distribution system uses wood, concrete, steel, ductile iron and fiberglass poles. The standard for all new distribution construction is Chromated Copper Arsenate ("CCA") treated wood poles as these CCA poles meet the strength requirements for most of the company's distribution line construction, have excellent life expectancy in Tampa Electric's service area (30+ years), are readily available, and cost effective.

The company's standard conductor for circuit feeders is 336 kcmil Aluminum Conductor, Steel Reinforced ("ACSR") with a 2/0 All Aluminum Alloy Conductor ("AAAC") neutral. Conductor sizes used for distribution laterals (overhead takeoffs from feeders) may either be #2, 2/0 or 4/0 AAAC with some older existing facilities containing #6 copper conductor.

**5.3.2.5 Construction Types**

Proper configuration selection is important for safety, maintenance and economics. The company typically maintains the existing line configuration for multi-phase line extensions. Customer requests for alternative distribution pole and construction types will be considered and if agreed upon, the customer(s) requesting would incur the incremental expense from standard service.

Triangular line configuration using fiberglass brackets is the preferred construction standard. It is the most economical to install and is particularly suited to situations involving restrictive Rights-of-Way ("ROW"), easements and clearances. Because of its narrow profile, it is also preferred for locations with numerous trees. Other construction types that may be used include vertical, modified vertical and wood, or fiberglass cross arms.

**5.3.2.6 Pole Loading Compliance**

Tampa Electric uses "PoleForeman," a pole loading software program to assure that Tampa Electric is following all NESC loading requirements and company construction standards. The program uses the company's construction standards with templates to model each pole and assist company distribution design technicians and distribution design engineers. The technician or engineer inputs the appropriate template, conductor, pole size and class, which the program uses to determine all loads on the pole. The program applies the loads to the structure and calculates the resulting stresses as a percent utilization of the pole.

**5.3.3 Underground Facilities**

**5.3.3.1 Standard Design**

Tampa Electric's standard underground distribution system consists of normally looped circuits operating at 13.2kV three-phase or 7.6kV single-phase primary voltages. The standard cable is 15kV strand-filled jacketed tree-retardant cross-linked polyethylene insulated aluminum cable with a copper concentric neutral. Tampa Electric's standard is to place all underground distribution cables in a conduit system buried at depths of 24 to 36 inches from the ground surface to the top of the conduit.

#### 5.3.3.2 Network Service

Tampa Electric has several types of underground services with associated facilities. One is standard underground service that is used in residential subdivisions and commercial areas, which are described above. Another is network service, which provides a higher level of reliability and operating flexibility.

Tampa Electric employs two types of network service. The first type is an integrated secondary grid network that serves the high-density load area in downtown Tampa. The second type is spot network systems that also serves certain high-density loads in the downtown Tampa network area.

The network systems provide redundant circuit feeds from a two-transformer substation and thus are designed to maintain service during a first contingency outage. The network systems are also designed to resist water intrusion and the equipment is in vaults, some of which are below-grade. However, the customer-owned electrical panels are not necessarily waterproof and will likely be severely impacted by saltwater intrusion. This will possibly delay power restoration to network customers in the event of a major storm with storm surge into the network areas.

### 5.3.4 Construction Standards in Coastal Areas

Tampa Electric's service area is partially bounded by Tampa Bay and has approximately 60 square miles of land in the Flood Zone 1 designated area as defined in Hillsborough County's Hazard Flood Maps and approximately 2.5 square miles of land in the

Oldsmar area in the Flood Zone 1 designated area as defined in Pinellas County’s Hazard Flood Maps. There is increased risk of storm surge, flooding and saltwater contamination along these coastal areas. Since 2008, the company’s standard is that new underground distribution facilities (padmounted transformers, switchgear and load break cabinets) shall be of stainless steel or aluminum construction and bolted to a concrete pad. Upgrading the material from mild steel to stainless steel or aluminum makes it more durable and typically extends equipment life after saltwater contamination. While using stainless steel or aluminum has significant benefits to storm hardening, the equipment is not waterproof and may require cleaning prior to re-energizing after a flooding event. In addition, Tampa Electric has begun using submersible switchgear for customers in locations prone to flooding or where the switchgear can be subjected to harsh conditions. Since 2004, all primary switchgear has been specified using 100 percent stainless steel enclosures, and since 2008 all padmounted transformers have been specified using 100 percent stainless steel enclosures to reduce the corrosive effects from salt spray, effluent irrigation spray and to help harden the equipment against the corrosive effects of a saltwater storm surge.

In 2015, Tampa Electric began using submersible padmount switchgear to harden the underground system in certain applications. This switchgear is designed to withstand intrusion from water, including salt-water, while remaining in service. This gear will be specifically used for those critical customers in areas where storm surge is expected to have a significant impact or those low-lying areas where the environment has caused non-submersible switchgear to fail.

### 5.3.5 Location of Facilities

Tampa Electric’s policy as stated in the DETM is to ensure that the route for new lines is located within the Public ROW or an electric utility easement. New residential lines shall be front lot construction and truck accessible. Commercial lines may be rear lot construction, but they must be truck accessible. This approach facilitates efficient access during installation and maintenance of the facilities. Prior to 1970 when this policy was instituted, some distribution facilities were constructed in rear lot easements. Communities or homeowner associations occasionally make inquiries regarding the relocation of overhead facilities from rear lot locations to the front of customer's properties. Tampa Electric evaluates each inquiry on a case-by-case basis for feasibility, practicality and cost-effectiveness.

### 5.3.6 Critical Infrastructure

Tampa Electric, in conjunction with local government emergency management, has identified the company's critical facilities and associated circuits feeding loads which are deemed necessary for business continuity and continuity of government. As such, critical community facilities are identified based on being most critical to the overall health of the community, including public health, safety or the national or global economy. Such facilities include hospitals, emergency shelters, master pumping stations, wastewater plants, major communications facilities, flood control structures, electric and gas utilities, EOC, as well as main police and fire stations, and others. The circuits serving these facilities have the highest restoration priority level. Tampa Electric has hardened several circuits which feed some of the most critical customers on the company's system to extreme wind criteria.

## 5.4 Transmission

This section of the Plan provides an overview of design considerations and references when performing a transmission structure analysis for new and existing facilities. This section is a broad discussion of transmission structure types, foundation design and design criteria.

#### 5.4.1 Design Criteria

There are two types of methodologies used to analyze pole strength. Tampa Electric uses the ultimate strength analysis for all wood and non-wood structures. However, it is acceptable and often recommended to use the working stress method for wood poles.

Tampa Electric designs and specifies all transmission facilities in accordance with the latest version of the NESC. All designs address NESC extreme wind and Grade B construction at a minimum. The extreme wind loads are applied to all attachments on the transmission structure regardless of attachment height.

Tampa Electric’s service area is largely within the 100 mph to 120 mph extreme wind contours referenced in the NESC. For design consistency, the 120-mph wind standard is applied on all 69kV structures throughout the service area. In addition, a 133-mph wind standard is applied to all 138kV and 230kV structures throughout Tampa Electric’s service area. The 133-mph wind standard exceeds the NESC requirements for extreme wind loading. This standard was adopted when Tampa Electric commissioned the first 230kV line in the company’s service area. Tampa Electric continues to support the 133-mph wind standard as the best practice for 138kV and 230kV line construction.

Since the inception of the NESC extreme wind standard, it has been applied to Tampa Electric transmission facilities. Tampa Electric historically has applied the 133-mph wind standard to 230kV facilities and in some cases an even higher wind speed has been applied when the company determined that the circuit would be very difficult to restore. An example of this higher wind standard is when the company replaced the transmission structures crossing the Alafia River. For these structures, a 150-mph wind standard was used.

### 5.4.2 Transmission Structures

#### 5.4.2.1 Voltage levels

Tampa Electric's transmission system consists of circuits operating at 230kV, 138kV and 69kV. These circuits consist of a minimum of three phase conductors and (usually) a static wire (ground). Additional facilities may exist or be incorporated in the design of a transmission structure, including additional transmission conductors, optical ground wire, communication conductors, distribution conductors and an assortment of wire attachments by joint users.

#### 5.4.2.2 Material types

Tampa Electric's transmission system consists of wood, concrete, aluminum, steel and composite supporting structures. Since 1991, Tampa Electric has used a standard that all new construction, line relocations and maintenance replacements will use pre-stressed spun concrete, steel or composite pole structures. Past practices included wood pole, aluminum and lattice steel structure design. Pre-stressed spun concrete, tubular steel and composite poles are now the preferred structure material types Tampa Electric installs when replacing or upgrading structures.

#### 5.4.2.3 Configuration Types

Tampa Electric uses multiple transmission structure configurations. Pre-stressed spun concrete poles and tubular steel poles are used in single or multiple pole configurations. The advent of pre-stressed spun concrete and tubular steel poles has permitted a more cost-effective, lower maintenance and higher strength option.

The configurations will vary widely when considering the many variables associated with transmission facilities. Some of these variables are:

- Number of circuits
- Conductor size
- Structure strength
- Span length
- Soil conditions
- ROW width
- Potential permitting requirements
- Utilization of adjacent land
- Environmental impacts
- Electric and magnetic field criteria
- Aesthetics
- Economics and cost–effectiveness
- Community input

Single pre-stressed spun concrete or tubular steel structure configurations have proven to be the most economical and maintainable choice given the work environment and constraints encountered while engineering and constructing transmission facilities. Prior to pre-stressed spun concrete and tubular steel technology, typical structure configurations commonly consisted of single wood pole or multiple wood pole structures, lattice aluminum H-frames and lattice steel towers.

**5.4.3 Foundations**

Direct embedment is the preferred foundation type used for pre-stressed spun concrete, tubular steel or composite structures. A direct embedded foundation typically has a specified depth and diameter. The direct embedded foundation also requires a segment of the superstructure to be embedded below ground, acting as part of the foundation, along with natural soil, crushed rock or concrete backfill.

When a structure location requires it, Tampa Electric uses an industry accepted program for foundation design. Soil borings are collected, or standard penetration tests are conducted to compile the appropriate soil data for foundation analysis.

### 5.5 Substation

Tampa Electric has developed and maintains a Substation Engineering Technical Manual ("SETM") which provides the company's personnel with the policies, procedures and technical date to the design of substation facilities owned and operated by the company. Information contained in the SETM along with the Standard Electrical Service Requirements ("SESR"), GR&S-OH, GR&S-UG and AMC, provide guidelines for designing, constructing and maintaining Tampa Electric's substation facilities.

Tampa Electric designs, constructs and maintains transmission and distribution substations and switchyards ranging from 13.2kV to 230kV. This includes performing siting studies, physical design, grading and drainage, foundation design, layout and design of control buildings, structure design and analysis, protection and control systems, and preparation of complete specifications for material, equipment and construction. The company currently has 216 substations.

#### 5.5.1 Design Philosophy

##### 5.5.1.1 Wind Strength Requirements

Tampa Electric designs the company's substations in accordance with the latest approved version of the NESC. Currently, all distribution substation structures are designed to withstand a wind load of 120 mph. All current design standards for 230kV generation facilities and 230kV transmission stations call for terminal line structures to withstand 133 mph wind loading along with the line tension of the transmission circuit.

The design standards summarized above meet the NESC loading criteria for extreme wind, Grade B construction. As previously stated, Tampa Electric's service area is within the 100 mph to 120 mph extreme wind contours referenced in the NESC.

**5.5.1.2 Equipment Elevations**

The company carefully evaluates equipment elevations when building on existing sites or when selecting future sites in the Flood Zone 1 designated area. Information on past flooding in localized areas and potential future storm surge levels are evaluated. Most equipment is built on steel supports and is above expected flood levels. Some equipment such as transformers can be submerged up to the point of attached cabinets and controls. Therefore, the major focus is on the elevation and water resistance of the control cabinets and related equipment. The sites and/or equipment are elevated based on the overall site permitting that must be done with the governmental and environmental agencies while taking into consideration the surrounding area.

**5.5.1.3 Protection**

Animal protection covers are installed on all new 13kV bushings, lightning arrestors, switches and leads. This helps prevent outages caused by animals and will also reduce damage from debris that may get inside the substation during a major storm event. Tampa Electric uses circuit switchers instead of fuses or ground switches on new and upgraded transformer installations. This design will clear a fault faster which minimizes damage and greatly reduces restoration time.

**5.5.1.4 Flood Zones**

The company carefully evaluates flood zones when building on existing sites or when selecting future sites. The company will continue to review existing sites in the Flood Zone 1 designated area. The major focus will be on the elevation and water resistance of control cabinets and related equipment. Prudent modifications will be made. Consideration will be given to whether there will be load to be served in the area of the substation immediately after a storm and if any load can be served from adjacent substations that are outside the flooded area.

#### 5.5.1.5 Other

When transformers are added to an existing substation or a transformer is upgraded, if needed, existing fences are removed, and new fences are installed to meet or exceed current NESC wind and height standards. At the same time, animal protection covers are installed on all 13kV bushings, lightning arrestors, switches and leads. This helps prevent damage from debris that gets inside the substation.

### 5.5.2 Construction Standards

Tampa Electric uses galvanized tubular steel structures in new distribution substations. The tallest structure is approximately 24 feet above grade, with most of the structures and equipment being below 17 feet. Distribution feeder circuits are designed to exit the substation via underground cables installed inside six-inch conduit.

In 230kV substations and 69kV switching stations, control buildings are used to house protection relays, communication equipment, Remote Terminal Unit ("RTU") monitoring equipment and substation battery systems. Previous construction methods used concrete block construction with poured concrete columns and concrete roof panels, which are designed to withstand winds of 120 mph without any damage to the building or the equipment housed inside. Control buildings currently being installed are prefabricated metal buildings designed for 150 mph wind loading. Tampa Electric installs eight-foot tall perimeter chain link fences designed to 120 mph or walls designed to 125 mph. This provides additional protection from wind-blown debris. Tampa

Electric has determined that this fencing standard is most effective in blocking debris and exceeds county codes.

**5.6 Deployment Strategy**

Tampa Electric’s 2020-2029 Storm Protection Plan’s deployment strategy will reduce storm restoration costs and customer outage duration following major storm events and enhance system reliability through the continuation of several core components of the company’s Storm Hardening Plans. The deployment strategy includes the continuation of legacy Storm Hardening Plan Initiatives and the implementation of new and expanded Storm Protection Plan Programs.

## 6 Storm Protection Plan Programs

Tampa Electric's proposed 2020-2029 SPP includes several newly developed incremental Storm Protection Programs, Projects and activities that resulted from the thorough and comprehensive analysis previously described. These new Programs, as well as the company's legacy Storm Hardening Plan activities, are described in this section. These Programs will achieve the goals, objectives and requirements of the Florida Legislature and the Commission.

### 6.1 Distribution Lateral Undergrounding

Tampa Electric's Distribution Lateral Undergrounding Program aims to strategically underground existing overhead lateral primary, lateral secondary and service lines. The expected benefits from this Program are:

- Reducing the number and severity of customer outages during extreme weather events;
- Reducing the amount of system damage during extreme weather;
- Reducing the material and manpower resources needed to respond to extreme weather events;
- Reducing the number of customer complaints from the reduction in outages during extreme weather events; and
- Reducing restoration costs following extreme weather events.

In addition to the many benefits that should be realized from distribution lateral undergrounding during extreme weather events, it will also provide additional blue-sky benefits such as:

- Reducing the number of momentary and prolonged unplanned outages;
- Reducing the number of customer complaints from outages; and
- Improving customer reliability and power quality.

Tampa Electric's Distribution System is currently comprised of the following Key Metrics:

- Total Circuit Miles: 11,800
- Total Overhead Miles: 6,251 (53 percent)
- Total Underground Miles: 5,549 (47 percent)
- Total Overhead Lateral Miles: 4,471
- Total Overhead Feeder Miles: 1,780
- Total Underground Lateral Miles: 4,949
- Total Underground Feeder Miles: 600
- Customers served off Laterals: 88 percent
- Customers served off Feeders: 12 percent

Tampa Electric and its customers have been fortunate because the company's service area has incurred only one direct hit from a large, strong, named storm in the last 15 years (Hurricane Irma in 2017). The table below reflects Tampa Electric's distribution system "OH versus UG" outage comparison across "day-to-day", Major Event Days, and Hurricane Irma.

| Tampa Electric's Distribution System Overhead versus Underground Outage Comparison (in Percent) | | | | |
|---|---|---|---|---|
| | **Distribution System** | **Day-to-Day Outages** | **Major Event Day Outages** | **Irma Repair/Replace** |
| **Overhead** | 53 | 81 | 91 | 99.60 |
| **Underground** | 47 | 19 | 9 | 0.40 |

These metrics show that the underground system proves to be much stronger and more resilient during extreme weather events. The Distribution Lateral Undergrounding Program is projected to receive the largest share of the SPP funding over the next ten years. This SPP Program is also expected to provide similar reliability improvements and restoration benefits (time and costs) during normal day-to-day operations and summer thunderstorm events.

As previously discussed, Tampa Electric used the 1898 & Co.

modeling tool to assist in the prioritization of individual Projects and to set the overall Program funding levels for the Distribution Lateral Undergrounding Program. Initial model runs provided the optimal 10-year SPP spending levels and demonstrated that this Program’s undergrounding Projects provided high net benefits to customers in the form of reduced restoration costs and CMI. Tampa Electric relied on the model output to confirm appropriate funding levels in alignment with the need to attract and sustain external workforces capable of executing a large-scale Distribution Lateral Undergrounding Program for the duration of the 2020-2029 SPP. The company also relied on the model output to identify the 2020-2021 Projects, selecting Projects that would allow it to most rapidly grow the Program, execute at small scale initially and develop operationally sound, sustainable and efficient processes. The individual Projects, the prioritization of these Projects and the annual Program funding levels are supported by the model. For operational efficiencies, laterals on the same feeder circuit were grouped and scheduled together in the same time frame. Laterals were then selected based on their ease of execution (e.g. fewer joint use attachers, fewer rear lot spans, and no major road or railroad crossings) balanced against their customer benefits. Strategically and operationally, these Projects are intended to allow the company to most rapidly complete projects to learn, adapt and enhance its processes to ensure the Program is sustainable, efficient and cost-effective. The 2020 activity will largely consist of designing, permitting, obtaining easements and attempting to coordinate with joint users on the identified Projects in detail included in Appendix “A”. While this currently reflects a construction quarter end date of “Q4 2020” for these Projects, the Projects can be completed only if all permitting and required easements are obtained. The company anticipates the permits and easements will be obtained, however if they cannot be, the company will begin the process by accelerating future planned Projects into

2020.

For the SPP years 2022 to 2029, the modeling tool grouped laterals by Feeder Circuit and prioritized them annually based on their net benefit to customers.

The table below shows the Distribution Lateral Undergrounding Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 24 | $8.0 |
| 2021 | 281 | $79.5 |
| 2022 | 316 | $108.1 |

The full detail of the supporting Distribution Lateral Undergrounding individual Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix "A".

**6.2 Vegetation Management**

Tampa Electric's Vegetation Management Program ("VMP") combines a continuation of its existing filed and approved distribution and transmission VMP activities with three additional strategic VM initiatives.

**6.2.1 Existing Vegetation Management Activities**

Tampa Electric currently trims the company's distribution system on a four-year cycle. This approach was approved by the Commission in Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI, issued June 12, 2012. The four-year cycle is flexible enough to allow the company to change circuit prioritization utilizing the company's reliability-based methodology. Since 2007, Tampa Electric has partnered with a third-party consultant and used their proprietary vegetation management software application. The software analyzes multi-year circuit performance data, trim cycles, and corrective and restoration costs to generate a priority list for circuit trimming for the four-year distribution trimming cycle. The software optimizes circuit selection in terms of both reliability and cost-effectiveness.

The company also adheres to a comprehensive vegetation management strategy for its transmission system. The company operates three categories of transmission lines 230kV, 138kV, and 69kV. For the circuits with voltages above 200kV, the company complies with Federal Energy Regulatory Commission (“FERC”) standard FAC-003-4. This standard imposes performance-based, risk-based, and competency-based requirements for vegetation management on these circuits. The company imposes a two-year vegetation management cycle for 138kV circuits, and a three-year cycle for 69kV circuits. The company’s vegetation management strategy for its transmission system includes the maintenance of the transmission ROWs.

#### 6.2.2 New VMP Initiatives

In addition to continuing its existing VMP plans, Tampa Electric partnered with Accenture to analyze various VMP strategies to further enhance the transmission and distribution facilities while reducing outage times and restoration costs due to extreme weather conditions. Accenture updated its existing vegetation management software to include the most recent outage, cost, and trim data, and to add functionality to estimate the value derived from activities that address only part of a circuit at a time. Tampa Electric and Accenture then analyzed and compared full and partial circuit vegetation management activities based on their expected cost and benefit during extreme weather events, as well as overall service reliability. Based on this analysis, Tampa Electric is proposing two additional distribution VM initiatives and one additional transmission VM initiative. The purpose of these additional VM initiatives is to enhance the company’s current cycles, specifically for the purpose of system storm hardening. These additional VM initiatives are:

Initiative 1: Supplemental Distribution Circuit VM
Initiative 2: Mid-Cycle Distribution VM
Initiative 3: 69 kV VM Reclamation

#### 6.2.2.1 Initiative 1: Supplemental Distribution Circuit VM

Tampa Electric and Accenture evaluated the costs and benefits of enhancing the current four-year distribution VM cycle by trimming additional miles each year to reduce the proximity between vegetation and electrical facilities. The team determined the cost of supplemental trimming would be justified by significant benefits including: (1) decreases in storm restoration costs; (2) decreases in corrective maintenance costs and day-to-day outage restoration costs; (3) improvements in day-to-day reliability; and (4) a reduction in the cost of the baseline 4-year trim cycle. Accenture analyzed multiple annual mileage increment scenarios. The analysis showed that each incremental increase in trimming will yield the above-described benefits, but these benefits eventually hit a point of diminishing returns. Accenture ultimately recommended 700 miles of supplemental VM would provide the greatest benefits for the estimated cost.

Circuit prioritization and selection will be centered around storm resiliency and mitigating outage risk on those circuits most susceptible to storm damage. Accenture’s VM software will generate annual circuit trim lists by emphasizing storm resiliency. The Supplemental Circuit VM initiative schedule by Tampa Electric’s Service Area and year for the affected miles and customers is detailed below:

| Supplemental Vegetation Management Project Schedule by Service Area | | | | | | |
|---|---|---|---|---|---|---|
| | 2020 | | 2021 | | 2022 | |
| Service Area | Miles | Customers | Miles | Customers | Miles | Customers |
| Central | 77.9 | 21,357 | 159.1 | 29,226 | 113.5 | 20,418 |
| Dade City | 99.9 | 5,208 | 6.2 | 484 | 127.6 | 5,578 |
| Eastern | 99.8 | 18,598 | 153.3 | 12,341 | 72.9 | 8,794 |
| Plant City | 76.7 | 9,702 | 25.2 | 2,443 | 202.2 | 8,347 |
| South Hillsborough | 15.3 | 2,264 | 20.5 | 2,427 | 20.2 | 3,236 |
| Western | 15.7 | 3,926 | 82.8 | 13,024 | 112.4 | 20,376 |
| Winter Haven | 16.8 | 1,277 | 63.1 | 5,063 | 43.2 | 5,784 |
| Total | 402.3 | 62,332 | 510.2 | 65,008 | 692 | 72,533 |

The total Supplemental Circuit VM initiative costs are detailed below for the 2020-2029 SPP:

| Supplemental Vegetation Management Project Costs (in thousands) | |
|---|---|
| 2020 | $3,200 |
| 2021 | $5,200 |
| 2022 | $6,100 |
| 2023 | $7,100 |
| 2024 | $4,800 |
| 2025 | $5,300 |
| 2026 | $6,500 |
| 2027 | $5,900 |
| 2028 | $5,900 |
| 2029 | $5,900 |

#### 6.2.2.2 Initiative 2: Mid-Cycle Distribution VM

Tampa Electric’s experience with existing VM activities is that some trees cannot be effectively maintained within the four-year distribution VM cycle because of their rapid growth rate. For instance, the company estimates that up to twenty-five percent of trees grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. Additionally, some trees develop into a threat to distribution facilities due to an evident defect or hazard trees. The current four-year cycle has limited tree removal potential. Fall-in trees were determined to be a major damage factor in recent storms.

The Mid-Cycle VM initiative is inspection-based and designed to identify and selectively mitigate these trees. Tampa Electric and Accenture's analysis showed that this initiative will lead to reductions in both extreme weather outages and restoration costs as well as day-to-day outage costs. For the first three years of the Storm Protection Plan, the company will inspect feeders that have not been trimmed in the last two years and then prescribe additional VM work based on the inspection findings. After the first three years, the company plans to expand the initiative to include laterals. The Mid-Cycle VM initiative schedule by Tampa Electric's Service Area and year for the affected miles and customers is detailed below:

| Mid-Cycle Vegetation Management Project Schedule by Service Area | | | | | | |
|---|---|---|---|---|---|---|
| | 2020 | | 2021 | | 2022 | |
| Service Area | Miles | Customers | Miles | Customers | Miles | Customers |
| Central | 0 | 0 | 48.6 | 17,262 | 36 | 9,488 |
| Dade City | 0 | 0 | 2.8 | 1,293 | 5.1 | 904 |
| Eastern | 0 | 0 | 17.3 | 4,730 | 34.5 | 12,007 |
| Plant City | 0 | 0 | 18 | 8,234 | 12 | 7,191 |
| South Hillsborough | 0 | 0 | 51.7 | 16,233 | 23 | 13,900 |
| Western | 0 | 0 | 58.8 | 27,318 | 53.3 | 19,073 |
| Winter Haven | 0 | 0 | 45.9 | 20,663 | 32.1 | 14,565 |
| Total | 0 | 0 | 243.1 | 95,733 | 196 | 77,128 |

The total Mid-Cycle VM Project costs are detailed below. The 2020 costs are associated with the initial inspections.

| Mid-Cycle Vegetation Management Project Costs (in thousands) | |
|---|---|
| **2020** | $100 |
| **2021** | $1,200 |
| **2022** | $3,500 |
| **2023** | $4,000 |
| **2024** | $5,600 |
| **2025** | $6,000 |
| **2026** | $5,700 |
| **2027** | $6,200 |
| **2028** | $7,300 |
| **2029** | $6,300 |

#### 6.2.2.3 Initiative 3: 69kV VM Reclamation

The 69kV Reclamation Project is designed to “reclaim” specific areas of the company’s 69kV system that are particularly problematic due to vegetative conditions. These areas are difficult and expensive to maintain and frequently contain hazard trees. While the company’s robust trim cycles are effective against vegetation to conductor encroachments on 90 percent of the 69kV circuits, the remaining portion are in areas that are either low-lying or restricted by vegetation overgrowth. The focus of this Project is to clear the vegetation undergrowth and remove the hazard trees. The company plans to clear the vegetation within the boundaries of the easement or property but outside of the current 15-foot vegetation-to-conductor clearance specification. The extent of trimming will be driven by the rights set forth in the company’s property deeds and easements, so the company plans to research existing easements and deeds and survey where necessary. Affected customers and property owners will be kept abreast of work occurring in their area.

An additional benefit to the Project is improved access. One of the VM lessons learned from recent storm recovery efforts is that unobstructed access to transmission facilities is critical to minimizing restoration times. Clearing these vegetation-obstructed areas will reduce outage potential, allow for faster restoration times, and lower restoration costs due to the following:

- Improving vegetation to conductor clearances will reduce blow-in outages;
- Removing hazard trees will reduce fall-in outages;
- Removing vegetation overgrowth will allow the ground to dry faster, promoting deeper tree roots and improving accessibility, reducing the need for access matting;
- Outage locations can be identified much easier, up to 200 percent faster;
- Damage assessment can be completed more accurately;
- Safer work sites reduce the number of personnel and equipment needed to restore; and
- Normal line and vegetation inspection and maintenance costs will be reduced by the improved clearances and unobstructed access.

The time to restore transmission outages is dependent on several factors, such as voltage, switching, design, and other facility impacts, but the key factor to restoration is accessibility. Outages that occur in areas obstructed by vegetation, on average, take up to 75 percent longer to restore. Tampa Electric has identified areas along the 69kV system where these vegetative conflicts and obstructions exist and mapped them to determine Project scope, cost, and schedule. The entire 69kV Vegetation Reclamation Initiative is a short-term initiative planned for four years beginning in 2020 and concluding in 2023. The Project scope and cost detail for the 69kV Vegetation Reclamation Initiative is listed below.

| Project Scope | | | Total Project Costs (in thousands) |
|---|---|---|---|
| Circuits | Customers | Length (miles) | |
| 170 | 84,000 | 83.2 | $2,185 |

#### 6.2.3 Estimated Costs – VMP

Tampa Electric and Accenture estimate that, in total, approximately 270 VM contract trimmers and six contract forestry inspectors will be needed for all distribution VM activities once the new initiatives are scaled up to their future steady state. The 69kV Reclamation Initiative will require approximately 40 VM total contract trimmers to complete.

### 6.3 Transmission Asset Upgrades

The Transmission Asset Upgrades Program is a systematic and proactive replacement Program of all Tampa Electric's remaining transmission wood poles with non-wood material. The company intends to complete this conversion from wood transmission poles to non-wood material poles during the timeframe of this initial ten-year SPP. Tampa Electric has over 25,400 transmission poles and structures with approximately 1,350 circuit miles of transmission facilities. Of these transmission structures, approximately 20 percent are supported with wood poles. Historically, the company's transmission hardening Program focused on replacing existing wood transmission poles with non-wood material upon a failed inspection. During replacement, the company would also upgrade existing hardware and insulators. From 2007 through 2019, the company hardened 8,971 wood transmission structures with non-wood material as a part of the existing Storm Hardening Plan. The company will continue to use the ongoing multiple transmission inspection methods to prioritize the replacement of existing wood transmission poles that fail inspection. Tampa Electric will also prioritize the systematic and proactive replacement of all other remaining wood transmission poles.

In the early 1990s, Tampa Electric made the decision to begin building all new transmission circuits with non-wood structures. Replacing all existing transmission wood poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, and more robust, wind loading standards than required at the time of installation. The Transmission Asset Upgrades Program will reduce restoration cost and outage times as a result of the anticipated reduction in the quantity of poles requiring replacement from an extreme weather event. Of the ten transmission poles replaced due to Hurricane Irma in 2017, nine were wood poles with no previously identified deficiencies that would warrant the pole to be replaced under the existing transmission hardening Program.

Tampa Electric used the 1898 & Co.'s resilience-based modeling to develop the initial prioritization of Projects. This initial prioritization is based upon the transmission circuit's historical performance relative to criticality of the transmission line, reducing customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. In order to account for technical and operational constraints like access and the long lead time for permits, the list was reviewed by Tampa Electric personnel for feasibility.

Once this review was complete a revised prioritization that incorporated access challenges, long lead time for permit requirements and scheduling constraints was developed. The revised prioritization is reflected in this ten-year SPP with Projects that are most feasible to implement accelerated into the first three years of the SPP. The remainder of the SPP years were scheduled by 1898 & Co.'s resilience-based model beginning in year 2023 to allow for scheduling, permitting and access issues to be addressed.

The table below shows the Transmission Asset Upgrades Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 21 | $5.6 |
| 2021 | 35 | $15.2 |
| 2022 | 28 | $15.0 |

The full detail of the supporting Transmission Asset Upgrades Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix "B".

## 6.4 Substation Extreme Weather Hardening

Tampa Electric's Substation Extreme Weather Hardening Program is designed to harden existing substations to minimize outages, reduce restoration times and enhance emergency response during extreme weather events. Hardening Projects within this Program could involve the installation of extreme weather protection barriers; installation of flood or storm surge prevention barriers; additions, modifications or relocation of substation equipment; modification to the designs of the company's substations; or other approaches identified to protect against extreme weather damage in or around the company's substations.

Tampa Electric engaged 1898 & Co. to perform preliminary analysis and prioritization of the company's 216 substations. The SLOSH model, described in the 1898 & Co. report included as

Appendix “F”, identified 59 of these 216 substations with some level of flooding risk and the height of a wall needed to mitigate that risk. The 59 substations were evaluated and prioritized in the model using only the single solution of building a flood wall around the perimeter of each substation. Using this methodology, the model identified 11 substations that were prioritized to be hardened within the 2020-2029 SPP.

Tampa Electric will begin this Program in early 2021 by engaging an additional third-party consultant that specializes in substation engineering and asset management to further identify and evaluate other potential hardening solutions beyond the single solution that was modeled. This study will include the 11 identified substations, as well as others that Tampa Electric subject matter experts determine have potential vulnerability to extreme weather. The study, to be completed by the end of 2021, will examine the potential for flooding for each substation, flood mitigation options, and provide an engineering recommendation for station flood protection or mitigation, if applicable. The study is estimated to cost $250,000 and will also include:

- High level cost estimates for the installation of a flood wall or other hardening solutions;
- Mitigation approaches and a scorecard based on prioritization of the hardening strategies intended to increase reliability; and
- An updated and refined prioritization list.

The Company expects the 2021 study and analysis to identify the proper hardening solution for each of the substations, with cost estimates that are more reflective of the unique characteristics of each substation. Once the study is complete, Tampa Electric will determine a final prioritized list of Substation Extreme Weather Protection Projects. The required Project-level information will be provided at the appropriate filing opportunity in the Storm Protection Plan Cost Recovery Clause Docket.

The table below shows the Substation Extreme Weather Hardening Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Substation Extreme Weather Hardening Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 0 | $0.0 |
| 2021 | 1 (Note 1) | $0.3 |
| 2022 | 0 | $0.0 |

Note 1: The Project identified in 2021 is the further study of potential substation solutions as described above.

### 6.5 Distribution Overhead Feeder Hardening

Tampa Electric's Distribution Overhead Feeder Hardening Program will strengthen the company's distribution system to withstand increased wind-loading and harsh environmental conditions associated with extreme weather events. This Program will provide the ability to reconfigure the electrical system to minimize the number of customers experiencing prolonged outages that may occur as a result of un-forecasted system conditions and unplanned circuit outages. The Distribution Overhead Feeder Hardening Program will focus on increasing the resiliency and sectionalizing capabilities of the distribution electrical system to better withstand extreme weather and minimize outages, outage durations and affected customer counts through two primary enhancements: Distribution Feeder Strengthening and Distribution Feeder Sectionalizing and Automation.

**6.5.1 Distribution Feeder Strengthening**

These enhancements will incorporate changes to the Company's distribution design standards to focus on the physical strength of Tampa Electric's distribution infrastructure. The company plans to harden selected feeders to meet NESC construction Grade B criteria with the Rule 250C (Extreme Wind) loading and strength criteria applied. This will involve the evaluation of the feeder, including a thorough review of the poles, conductor and equipment to determine the upgrades necessary to ensure the feeder meets new hardened design and construction standards.

**6.5.2 Distribution Feeder Sectionalizing and Automation**

These enhancements involve increasing the installation of automation equipment, reclosers, trip savers and other supporting sectionalizing infrastructure on existing distribution circuits. These devices provide many benefits that will improve the performance of the overall distribution system during extreme weather events such as:

- Allowing for the automatic transfer of load to neighboring feeders in the event of unplanned outages that can occur during both normal and extreme weather events;
- Allowing for the network to be re-configured automatically to minimize the number of customers experiencing prolonged outages during both normal and extreme weather events; and
- Reducing restoration time by isolating only those parts of the electrical system that contain faults that require assessment, investigation, follow-up and repair.

Upgraded conductor size will support the increased loading that could occur from such activity and provide additional ability to reconfigure the distribution system. Upgraded additional transformer capacity at strategic substations will ensure maximum load restoration capacity.

Combined, these design and standards changes will increase the overall resiliency of the company's feeder distribution system to withstand all ranges of extreme weather events.

Tampa Electric has approximately 800 distribution circuits, which were prioritized based on their reliability performance and priority customer count to identify the target circuits for the 2020-2022 timeframe. Reliability performance was considered for both extreme weather and blue-sky days with a higher weighting factor assigned to circuit reliability under extreme weather conditions.

With a list of (22) circuits targeted for an OH distribution investment, Tampa Electric identified improvements on each circuit that would result in increased sectionalizing of the system with the following measures:

- Target a 200-500 maximum customer range on each segment;
- Limit segment distance to two to three miles; and
- Limit serving between two to three MW of load on each segment.

For 2020 implementation, the company identified circuits for improvement that require minimal engineering, minimal lead-time on material and do not require permits. Circuit improvements that require complex engineering, longer lead-times for materials and could result in local and state permits and approval have been scheduled for 2021 and 2022 in-service dates. The remainder of the SPP years (2023-2029) were prioritized by the model.

The table below shows the Distribution Overhead Feeder Hardening Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 5 | $6.5 |
| 2021 | 18 | $15.4 |
| 2022 | 13 | $29.6 |

The full detail of the supporting Distribution Overhead Feeder Hardening individual Projects as required by Rule 25-6.030(3)(2)1-5 is included as Appendix "D".

### 6.6 Transmission Access Enhancement

The Transmission Access Enhancement Program is designed to ensure the company always has access to its transmission facilities for the performance of restoration. Immediate and permanent access to these facilities reduces restoration times and restoration costs. Increased power demands and changes in topography and hydrology related to customer development, along with several years of active storm seasons, have impacted the access to the existing transmission infrastructure. This Program will significantly enhance access to critical routes throughout the company's transmission corridors that were impacted by these environmental and social changes. The Program is divided into two components: Access Roads and Access Bridges.

**Access Roads:** These Projects are designed to restore access to areas where changes in topography and hydrology have negatively impacted existing access roads or created the need to establish new access roads. The access roads are Tampa Electric's primary route to critical transmission facilities for installation, maintenance, and repair. In addition, the FERC standard, FAC-003-4, requires that all utilities maintain a robust vegetation management Program for all high voltage circuits, 200kV and above. These routes are necessary to ensure compliance.

The company has identified a total of 70 potential Access Road Projects, subdivided by circuit. In many cases, more than one circuit benefits from the installation or repair of the road. While engineering will determine the exact scope and cost of the road, company subject matter experts developed a preliminary cost estimate for each Project that was used in the 1898 & Co. model for cost-benefit prioritization. The costs were based on the number of road miles and construction type. The total Access Roads initiative costs are detailed below for the 20 Access Road Projects proposed in the 2020-2029 SPP:

| **Access Road Projects Costs (in thousands)** | |
|---|---|
| **2020** | $0 |
| **2021** | $604 |
| **2022** | $391 |
| **2023** | $0 |
| **2024** | $810 |
| **2025** | $978 |
| **2026** | $0 |
| **2027** | $3,325 |
| **2028** | $1,982 |
| **2029** | $1,065 |

Government permitting is the primary driver of schedule, as the plan and approval process for a single permit can take up to twenty-four months. Since most proposed access roads are in low-lying or wetland areas, most will require review and approval from several agencies, e.g., State, County, Army Corps of Engineers. Permit fees and the associated mitigation costs are the most volatile cost variable. Actuals will be closely tracked, compared to estimates, and adjusted as necessary to ensure the Projects remain on budget.

**Access Bridges:** These Projects are designed to enhance or replace the company’s current system of bridges used to access its “off road” transmission facilities. As with Access roads, access bridges are a primary route to critical transmission facilities for installation, maintenance, and repair. In addition, the FERC standard, FAC-003-4, requires all utilities to maintain a robust vegetation management Program for all high voltage circuits, 200kV and above. These routes are also necessary to ensure compliance. The last several storm seasons have impacted the integrity of the company’s bridge network. While necessary repairs were made post-storm to ensure the bridges remain safe for travel, the repairs that were made were temporary to allow for a safe and timely restoration. Tampa Electric’s system hardening activities place additional strain on the bridges. For example, the company’s aggressive wooden pole replacement Program has created increases in bridge traffic and load from the heavier transmission vehicles needed to install the reinforced steel poles. The Access Bridge Project will bring the bridge(s) up to capacity to meet the current weight of the company’s transmission vehicles and secure pilings and position in and over the waterways to ensure constant access to critical transmission infrastructure, particularly during extreme weather events.

The company currently maintains a total of 24 bridges, with three of these bridges being recently installed in a transmission upgrade Project. In addition to the 21 current bridges identified for replacement, the company identified an additional five bridges for a net total of 26 potential bridge Projects. The total Access Bridges initiative costs are detailed below for the 17 Access Bridge Projects proposed in the 2020-2029 SPP:

| Access Bridge Project Costs (in thousands) | |
|---|---|
| **2020** | $0 |
| **2021** | $780 |
| **2022** | $1,118 |
| **2023** | $1,606 |
| **2024** | $853 |
| **2025** | $360 |
| **2026** | $354 |
| **2027** | $0 |
| **2028** | $0 |
| **2029** | $601 |

Government permitting is the primary driver of schedule, as the plan and approval process for a single permit can take up to twenty-four months. The company expects all access bridges will require review and approval from several agencies, e.g., State, County, Army Corps of Engineers. Permit fees and associated mitigation costs are the most volatile cost variable. Actuals will be closely tracked, compared to estimates, and adjusted as necessary to ensure that each Project remains on budget.

Tampa Electric used 1898 & Co.'s resilience-based modeling described in Appendix "F" to evaluate the cost-benefit expectation for each of the 96 Access Enhancement Projects. Since permitting is the primary driver of the schedule, it was assumed that Access Projects could not begin until 2021. The model then developed a prioritization of these Projects based on the cost-benefit expectations. This SPP Plan reflects the completion of 37 Access Enhancement Projects over the ten-year SPP.

The table below shows the Transmission Access Enhancements Program's Projects by year and projected costs for the first three years of the 2020-2029 SPP:

| | Tampa Electric's Transmission Access Enhancements Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 0 | $0.0 |
| 2021 | 8 | $1.4 |
| 2022 | 6 | $1.5 |

### 6.7 Infrastructure Inspections

Tampa Electric’s Infrastructure Inspection Program is a comprehensive inspection Program that combines the existing Commission approved Storm Hardening Plan Initiatives of: Wood Pole Inspections, Transmission Structure Inspections, and the Joint Use Pole Attachment Audit.

The company originally developed the wooden pole inspection initiative to comply with Order No. PSC-06-0144-PAA-EI, which requires each investor-owned electric utility to implement an inspection Program for its wooden transmission and distribution poles on an eight-year cycle based on the requirements of the NESC. The company developed the transmission structure inspection and joint-use attachment audit initiatives to comply with Commission Order No. PSC-06-0351-PAA-EI.

Tampa Electric has not historically attempted to quantify the benefits of these inspection activities because they were required by Commission Order. In those Orders, the Commission found that these activities offered significant storm resiliency benefits. For instance, the Commission found that wood pole inspections and corrective maintenance “can reduce the impact of hurricanes and tropical storms upon utilities’ transmission and distribution systems.” Order No. PSC-06-0144-PAA-EI. The Commission also found that wood pole inspections reduce restoration times because, in the named storms in Florida in 2004 and 2005, "the number of failed poles resulting from a storm [were] correlated with the number of days required to restore service to customers." Order No. PSC-06-0144-PAA-EI. The Commission later found that a transmission structure inspection program would offer similar benefits. Order No. PSC-06-0351-PAA-EI. The Commission also found that a joint use attachment audit would provide storm resiliency benefits because "[u]tility poles that are overloaded or approaching overloading are subject to failure in extreme weather." Order No. PSC-06-0351-PAA-EI. Tampa Electric believes that infrastructure inspection activities still offer these benefits.

Tampa Electric also believes that the costs of these activities are outweighed by their benefits. In Order No. PSC-06-0144-PAA-EI, the Commission analyzed the potential costs of a mandatory wooden pole inspection program and concluded: "The cost of conducting these inspections, while not insignificant, must be compared to the storm restoration costs incurred in 2004 and 2005." Order No. PSC-06-0144-PAA-EI. Tampa Electric agrees with this assessment and concludes that the costs of infrastructure inspections are outweighed by the associated reduction in restoration costs and outage times identified by the Commission.

### 6.7.1Wood Pole Inspections

Tampa Electric's Wood Pole Inspection Initiative is part of a comprehensive program initiated by the FPSC for Florida investor-owned electric utilities to harden the electric system against severe weather.

This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI which requires each investor-owned electric utility to implement an inspection program of its wooden transmission and distribution poles on an eight-year cycle based on the requirements of the NESC. This program provides a systematic identification of poles that require repair, reinforcement or replacement to meet strength requirements of the NESC.

The wood pole inspections will be conducted on a substation circuit basis with a goal of inspecting the entire wood pole population every eight years. An average of 36,000 wooden distribution poles will be inspected annually with each pole receiving a visual inspection, a sound & bore procedure and a groundline/excavation inspection (except for chromated copper arsenate "CCA" poles less than 16 years of age.)

Tampa Electric estimates that this initiative will cost approximately $1,000,000 annually over the ten-year horizon of this SPP.

Tampa Electric's wood pole inspection strategy takes a balanced approach and has produced excellent results in a cost-effective manner. The future inspections coupled with the company's pole replacement activities will ultimately harden Tampa Electric's distribution system.

### 6.7.2 Transmission Inspections

Tampa Electric will continue to conduct the multi-pronged inspection approach the company has historically applied to the system which has led to the transmission system having a history of strong reliability performance. This approach includes the eight-year above ground structure inspection cycle, eight-year ground line wood inspection cycle, annual ground patrol, annual aerial infrared patrol, annual substation inspection cycle and the pre-climb inspection requirement. Tampa Electric will continue these inspections and will also continue the company's ongoing efforts to monitor and evaluate the appropriateness of its transmission structure inspection program to ensure that any cost-effective storm hardening or reliability opportunities found are taken advantage of.

Tampa Electric estimates the annual cost of this initiative is approximately $360,000 over the ten-year Plan horizon. Tampa Electric believes this cost is justified because the Commission previously found that a robust transmission inspection program was necessary.

#### 6.7.2.1 Groundline Inspections

Tampa Electric conducts groundline inspections in compliance with the Commission’s order requiring groundline inspection of wooden transmission structures. A groundline inspection includes excavation, sounding and boring wood poles. Excavation requires removing earth at the base of the pole around the entire circumference to a minimum depth of 18 inches below groundline. All poles passing the excavation inspection will then be sounded with a hammer. If sounding provides evidence of possible interior voids or rot, at least one boring shall be made where the void is indicated. If rot or voids are detected, enough boring shall be made so that the extent can be determined. Poles set in concrete, or otherwise inaccessible below groundline, shall be bored at least twice at groundline at a 45-degree downward direction. All bored holes shall be plugged with treated dowels. Groundline inspections are performed on an eight-year cycle. Each year approximately 12.5 percent of all wooden transmission structures are scheduled for inspection. For 2020 through 2022, the company plans to perform approximately 1,750 groundline inspections over the three-year period.

#### 6.7.2.2 Ground Patrol

The ground patrol is a visual inspection for deficiencies including poles, insulators, switches, conductors, static wire and grounding provisions, cross arms, guying, hardware and encroachment. The ground patrol will include identification of vegetation encroachment as well as all circuit deficiencies. All transmission circuits are patrolled by ground at least once each year.

**6.7.2.3 Aerial Infrared Patrol**

The aerial infrared patrol is planned annually on the entire transmission system. It is performed by helicopter with a contractor specializing in thermographic power line inspections and a company employee serving as navigator and observer. This inspection identifies areas of concern that are not readily identifiable by normal visual methods as well as splices and other connections that are heating abnormally and may result in premature failure of the component. This inspection also identifies obvious system deficiencies such as broken cross arms and visibly damaged poles. Since many of these structures are on limited access ROW, this aerial inspection provides a frequent review of the entire transmission system and helps identify potential reliability issues in a timely manner.

**6.7.2.4 Above Ground Inspections**

Above ground inspections are performed on transmission structures on an eight-year cycle; therefore, each year approximately 12.5 percent or one-eighth of transmission structures are inspected. This inspection will be performed by either an internal team member or contractor specializing in above ground power pole inspections and may be performed by climbers, bucket truck, helicopter or Unmanned Aerial Systems (“UAS” or Drones). The above ground inspection is a comprehensive inspection that includes assessment of poles, insulators, switches, conductors, static wire, grounding provisions, cross arms, guying, hardware and encroachment issues. This program provides a detailed review of the above ground condition of the pole and the associated hardware on the structure. Due to advances in technology, the capabilities of

UAS has allowed the company to complete the Above Ground Inspections in conjunction with the Ground Patrol utilizing the UAS for an aerial view of the structures identified for the comprehensive inspection.

For 2020 through 2022, annual above ground inspections are planned on approximately 10,500 structures. This is in line with the company’s petition that changed the above ground inspection cycle from a six-year cycle to an eight-year cycle which was approved in Docket 20140122-EI, Order No. PSC-14-0684-PAA-EI and confirmed by Consummating Order No. PSC-15-0017-CO-EI.

#### 6.7.2.5 Substation Inspections

Tampa Electric performs inspections of distribution substations annually and inspections of transmission substations quarterly. The substation inspections include visual inspection of the substation fence, equipment, structures, control buildings and the integrity of grounding system for all equipment and structures.

Tampa Electric estimates that the annual cost of these inspections is approximately $150,000 over the ten-year horizon of the SPP.

#### 6.7.2.6 Pre-Climb Inspections

Tampa Electric crews are required to inspect wooden transmission & distribution poles prior to climbing. As part of these inspections, the employee is required to visually inspect each pole prior to climbing and sound each pole with a hammer if deemed necessary. These pre-climbing inspections serve to provide an additional safety-oriented integrity check of poles prior to the employee ascending the pole and may also result in the identification of any structural deterioration issues.

There are no costs associated with this activity since it occurs only when an employee is climbing a pole for another purpose.

#### 6.7.3 Joint Use Pole Attachments Audit

Tampa Electric will continue to conduct comprehensive loading analyses to ensure the company's poles with joint use attachments are not overloaded and meet the NESC or Tampa Electric Standards, whichever is more stringent. These loading analyses are a direct effort to lessen storm related issues on poles with joint use attachments. All current joint use agreements require attaching entities to apply for and gain permission to make attachments to Tampa Electric's poles. Once the application is received, an engineering assessment of every pole where attachments are being proposed will have a comprehensive loading analysis performed. If the loading analysis determines that additional support is necessary, all upgrades will be made prior to notifying the joint use attacher that their construction is ready for attachments.

Tampa Electric's audit of joint use attachments is an important step in documenting all pole attachments. A critical component of the audit is finding pole attachments that the company is not aware of. If an unauthorized attachment is found, the company can perform a comprehensive pole loading analysis to ensure the pole is not overloaded and ensuring that all safety, reliability, capacity and engineering requirement are met.

The necessity for the audit arises due to the significant wind loading and stress that pole attachments can have on a pole and the fact that some attachments are made without notice or prior engineering.

There is no incremental cost of this initiative as each audit is ultimately paid for by the joint attacher.

#### 6.7.4 Infrastructure Inspections Summary

The Infrastructure Inspection Program has no estimated completion date because the inspection activities are continuous and ongoing. The infrastructure inspection activities are either part of an ongoing cycle – such as wood pole and transmission structure inspections – or only occur when triggered by a specific event – such as pre-climb and joint use inspections. Given the nature of this Program, Tampa Electric concluded that it was not practical or feasible to identify specific Storm Protection Projects under this Program. Instead, the table below shows the number of infrastructure inspections the company is projecting over the 2020-2022 storm Protection Plan period.

| Projected Number of Infrastructure Inspections | | | |
|---|---|---|---|
| | **2020** | **2021** | **2022** |
| **Joint Use Audit** | Note 1 | | |
| **Distribution** | | | |
| Wood Pole Inspections | 22,500 | 22,500 | 35,625 |
| Groundline Inspections | 13,275 | 13,275 | 21,018 |
| **Transmission** | | | |
| Wood Pole/Groundline Inspections | 702 | 367 | 707 |
| Above Ground Inspections | 2,949 | 3,895 | 3,396 |
| Aerial Infrared Patrols | Annually | Annually | Annually |
| Ground Patrols | Annually | Annually | Annually |
| Substation Inspections | Annually | Annually | Annually |

Note 1: Tampa Electric completed its most recent Joint Use Pole Attachment Audit in the first quarter of 2020.

The table below provides the annual O&M expenses for each of the inspection programs for the 2020-2022 period.

| **Projected Costs of Infrastructure Inspections (in thousands)** | | | |
|---|---|---|---|
| | **2020** | **2021** | **2022** |
| **Distribution** | | | |
| Wood Pole/Groundline Inspections | $708 | $1,000 | $1,020 |
| **Transmission** | | | |
| Wood Pole/Groundline Inspections | $60 | $61 | $62 |
| Above Ground Inspections | $10 | $10 | $10 |
| Aerial Infrared Patrols | $110 | $112 | $114 |
| Ground Patrols | $145 | $148 | $151 |
| Substation Inspections | $140 | $143 | $146 |

### 6.8 Legacy Storm Hardening Plan Initiatives

The final category of storm protection activities consists of those legacy Storm Hardening Plan Initiatives that are well-established and steady state and for which the company does not propose any specific Storm Protection Projects at this time. Tampa Electric will continue these activities because the company believes they continue to offer the storm resiliency benefits identified by the Commission in Order No. PSC-06-0351-PAA-EI, which required the company to perform these activities. Tampa Electric cannot offer an estimated completion date for this Program because the initiatives are still mandated by the Commission and because the initiatives are all integrated into the company’s ongoing operations. Historically, Tampa Electric has not performed a formal cost benefit analysis for these activities because they were mandated by the Commission. Instead, the company evaluated projects under these initiatives based upon potential negative impacts on public safety and health, magnitude of impact on customers likely affected by an outage, environmental impacts, and access constraints that may exist following a potential major storm. Once the company selected a storm hardening project, Tampa Electric would then perform an internal formal cost analysis prior to initiating the project. In this internal analysis, the company would project the costs and estimate the benefits that should be realized. Tampa Electric recognizes that assigning a monetary value to customer benefits is challenging due to the lack of specific information about the financial impacts of outages, and because assigning value to public safety and health may skew the project's benefit analysis.

### 6.8.1 Geographic Information System

Tampa Electric's Geographic Information System ("GIS") will continue to serve as the foundational database for all transmission, substation and distribution facilities. Development and improvement of the GIS continues. All new computing technology requests and new initiatives are evaluated with a goal to eliminate redundant, exclusive and difficult to update databases as well as to place emphasis on full integration with Tampa Electric's business processes. These evaluations further cement GIS as the foundational database for Tampa Electric's facilities.

Tampa Electric does not propose any GIS Storm Protection Projects over the ten-year planning horizon. The company will, however, continue ongoing activities to improve the functionality and ease of use of the GIS for the company's GIS users. Two examples of these ongoing activities include the GIS User's Group, which meets to review, evaluate and recommend enhancements for implementation. The second ongoing activity is the annual publication of the Tampa Electric GIS Annual Report. Tampa Electric does not propose any specific Storm Protection Projects due to the reasons identified above.

Tampa Electric estimates the annual cost of maintaining and operating the GIS Program is $0 because the company's GIS system is an integral system used by the company to maintain its transmission and distribution asset information. Tampa Electric will continue to update and make improvements/enhancements to its GIS as needed.

### 6.8.2 Post-Storm Data Collection

Tampa Electric has implemented a formal process to randomly sample system damage following a major weather event in a statistically significant manner. This information will be used to perform forensic analysis to categorize the root cause of equipment failure. From these reports, recommendations and possible changes will be made regarding engineering, equipment and construction standards and specifications. A hired third party of data collection specialists will patrol a representative sample of the damaged areas of the electric system following a major storm event and perform the data collection process. At a minimum, the following types of information will be collected:

- Pole/Structure – type of damage, size and type of pole, and likely cause of damage;
- Conductor – type of damage, conductor type and size, and likely cause of damage;
- Equipment – type of damage, overhead or underground, size, and likely cause of damage; and
- Hardware – type of damage, size and likely cause of damage.

Third party engineering personnel will perform the forensic analysis of a representative sample of the data obtained to evaluate the root cause of failure and assess future preventive measures where possible and practical. This may include evaluating the type of material used, the type of construction and the environment where the damage occurred including existing vegetation and elevations. Changes may be recommended and implemented if more effective solutions are identified by the analysis team.

The company does not propose any specific post-storm data collection Projects under this Program because there will only be post-storm data collection activity if a major weather event occurs, and the company cannot predict when or if those events will occur during the ten-year planning horizon.

The incremental cost of this initiative is estimated to be approximately $113,000 per storm and will depend on the severity of the storm and extent of system damage.

**6.8.3 Outage Data - Overhead and Underground Systems**

Tampa Electric tracks and stores the company's outage data for overhead and underground systems in a single database called the Distribution Outage Database ("DOD"). The DOD is linked to and receives outage data from the company's EMS and OMS. The DOD tracks outage records according to cause and equipment type and can support the following functionality:

- Centralized capture of outage related data;
- Analysis and clean-up of outage-related data;
- Maintenance and adjustment to distribution outage database data;
- Automatic Generation and distribution of canned reliability reports; and
- Generating ad hoc operational and managerial reports.

The DOD is further programmed to distinguish between overhead and underground systems and is specifically designed to generate distribution service reliability reports that comply with Rule 25-6.0455, F.A.C.

In addition to the DOD and supporting processes, the company's overhead and underground systems are analyzed for accurate performance. The company also has established processes in place for collecting post-storm data and performing forensic analysis to ensure the performance of Tampa Electric's overhead and underground systems are correctly assessed.

The company does not propose any specific DOD Projects because there will only be DOD activity when there are storm related outages, and the company cannot predict when storm-related outages will occur during the ten-year planning horizon.

Tampa Electric does not forecast any annual DOD-related expenditures over the ten years of the SPP because costs are only incurred during a storm. The cost of this initiative is estimated to be approximately $100,000 per storm.

### 6.8.4 Increase Coordination with Local Governments

Tampa Electric representatives will continue to focus on maintaining existing vital governmental contacts and participating on disaster recovery committees to collaborate in planning, protection, response, recovery and mitigation efforts. In addition, Tampa Electric representatives will continue to communicate and coordinate with local governments on vegetation management, search and rescue operations, debris clearing, and identification of critical community facilities. Tampa Electric will participate with local and municipal government agencies within its service area, as well as the FDEM, in planning and facilitating joint storm exercises. In addition, Tampa Electric will continue to be involved in improving emergency response to vulnerable populations.

The company does not propose any specific local government coordination Projects because these activities occur intermittently and often on an unplanned basis before, during, and after severe weather events.

There are no incremental costs associated with this activity.

**6.8.5 Collaborative Research**

Tampa Electric will continue the company's participation in collaborative research effort with Florida's other investor-owned electric utilities, several municipals and cooperatives to further the development of storm resilient electric utility infrastructure and technologies that reduce storm restoration costs and outages to customers.

This collaborative research is facilitated by the Public Utility Research Center ("PURC") at the University of Florida. A steering committee comprised of one member from each of the participating utilities provides the direction for research initiatives. Tampa Electric signed an extension of the memorandum of understanding with PURC in December 2018, effective January 1, 2019, for two years. The memorandum of understanding will automatically extend for successive two-year terms on an evergreen basis until the utilities and PURC agree to terminate the agreement.

The company does not propose any specific collaborative research Projects over the ten-year period of the SPP. Tampa Electric does not estimate that there will be any collaborative research costs over the same ten-year horizon.

**6.8.6 Disaster Preparedness and Recovery Plan**

A key element in minimizing storm-caused outages is having a natural disaster preparedness and recovery plan. A formal disaster plan provides an effective means to document lessons learned, improve disaster recovery training, pre-storm staging activities, and post-storm recovery. The Commission's Order No. PSC-06-0351-PAA-E1, issued on April 25, 2006, within Docket No. 20060198-E1 required each investor-owned electric utility to develop a formal disaster preparedness and recovery plan that outlines its disaster recovery procedures and maintain a current copy of its utility disaster plan with the Commission.

Tampa Electric will continue to be active in many ongoing activities to support the restoration of the system before, during and after storm activation. The company will continue to lead or support disaster preparedness and recovery plan activities such as planning, training and working with other electric utilities and local government to continually refine and improve the company's ability to respond quickly and efficiently in any restoration situation.

Tampa Electric's Emergency Management plans address all hazards, including extreme weather events and are reviewed annually. Tampa Electric follows the policy set by TECO Energy for Emergency Management and Business Continuity which delineates responsibilities at the employee, company and community levels.

Tampa Electric will also continue to plan, participate in, and conduct internal and external preparedness exercises, collaborating with government emergency management agencies, at the local, state and federal levels. Internal company exercises focus on testing lessons learned from prior exercises/activations, new procedures, and educating new team members on roles and responsibilities in the areas of incident command, operations, logistics, planning and finance. The scope and type of internal exercises vary from year to year based on exercise objectives defined by a cross-functional exercise design team, following the Homeland Security Exercise and Evaluation Program ("HSEEP"). External preparedness exercises are coordinated by local, state and federal governmental emergency management agencies. Tampa Electric personnel participate in these exercises to test the company's internal emergency response plans, including coordination with Emergency Support Functions ("ESF") to maintain key business relationships at local Emergency Operation Centers ("EOC"). Like Tampa Electric, the exercise type (tabletop, functional or full-scale) and scope varies from year to year, and depending upon the emergency management agencies' exercise objectives, Tampa Electric participants may not be included.

Annually, Tampa Electric participates in the State of Florida's hurricane exercise with the FPSC, which often coincides with exercises conducted by Hillsborough, Pasco, Pinellas and Polk counties. In addition, municipalities within Tampa Electric's service area (Oldsmar, Plant City, Tampa and Temple Terrace) may also host exercises and/or pre-storm season briefings. For example, in 2019, Tampa Electric participated in exercises and/or pre-storm briefings hosted by the State of Florida (in conjunction with FPSC), Hillsborough and Pinellas counties, as well as the cities of Oldsmar, Tampa and Temple Terrace. However, in 2020, Tampa Electric has been advised that the State of Florida will not conduct an annual hurricane exercise. As a result, some counties and municipalities are following the State's lead.

Tampa Electric has been incorporating Lessons Learned from Hurricane Irma and the company's experience supporting the restoration for Hurricane Michael into the company's Emergency Response plans. While the updates cover a broad category or processes, a focus has been on insuring the plan can scale up to handle major storms (Cat 3, 4, 5), in Logistics (life support) and the ability to restore internal communications in the event public networks are negatively impacted (Internet, cellular and satellite).

Tampa Electric will implement a Damage Assessment tool as an integrated part of its Advanced Distribution Management System ("ADMS") scheduled for implementation in 2021.

The total cost to support all Emergency Management activities and initiatives is estimated to be $300,000 annually.

**6.8.7 Distribution Pole Replacements**

Tampa Electric's distribution pole replacement initiative starts with the company's wood pole inspections and includes designing, utilizing conductors and/or supporting structures, and constructing distribution facilities that meet or exceed the company's current design criteria for the distribution system. The company will continue to appropriately address all poles identified through its Infrastructure Inspection Program.

Given that this is a reactive activity (poles are replaced or restored only when they fail an inspection), Tampa Electric concluded that it was not practical or feasible to identify specific distribution pole replacement Storm Protection Projects.

Tampa Electric estimates the annual capital and O&M costs of this initiative is approximately $13,300,000 over the ten-year Plan horizon.

**6.8.8 Legacy Storm Hardening Plan Initiatives Costs**

The table below shows the projected costs for the first three years of the 2020-2029 SPP for the Legacy Storm Hardening Plan Initiatives:

| | Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions) | |
|---|---|---|
| | Disaster Preparedness and Recovery Plan | Distribution Pole Replacements |
| 2020 | $0.3 | $9.9 |
| 2021 | $0.3 | $11.8 |
| 2022 | $0.3 | $15.5 |

# 7 Storm Protection Plan Projected Costs and Benefits

Tampa Electric developed the projected 2020-2029 SPP costs by examining the time, the scope of work, and reasonably expected costs for each of the SPP Programs. To develop the company's estimations of costs, Tampa Electric relied upon the following key underlying assumptions:

1. Initially, the company identified the level of work and associated costs that could be successfully managed and physically performed annually to improve storm performance. This initially was determined to be between 100 to 200 million dollars on an annual basis, based upon work constraints.
2. Recognizing the sustained amount of work it would take for external resource companies to physically build or obtain a work force that could support several ongoing Storm Protection Programs.
3. Recognizing that there will be some competition for resources between utilities which could push costs upward.
4. Identification of the range of work necessary for each Storm Protection Program and the feasibility of success with external resources.
5. The costs would be made up of new incremental capital and O&M costs for each of the proposed Storm Protection Programs and their associated Projects.
6. Tampa Electric and 1898 & Co. ran unconstrained modeling which optimized the company's 2020-2029 spend at approximately $1.5 billion over the ten-year Plan.
7. Tampa Electric and 1898 & Co. ran constrained modeling which further supported the annual optimal spend to be between 100 to 200 million on an annual basis.
8. Actual historical costs would be used where the company has significant history and recent experience in developing the cost for each type of Project. Costs were also analyzed for impacts for potential competition and

future contractor capacity impacts.

9. Costs were validated for reasonableness and range by a variety of means, either in discussions amongst internal team members with this experience, discussions with Accenture LLP and 1898 & Co., or discussions with neighboring utilities.
10. Costs were used to complete SPP programs within the designated proposed timeline as described in the Transmission Asset Upgrade Program and the 69kV Reclamation initiative within the Vegetation Management Program.
11. Recognizing costs were projected based upon single solution modeling for the Substation Extreme Weather Hardening Program. The company needs to evaluate other potential solutions and opportunities before committing to an appropriate cost-effective solution for Tampa Electric's substations.
12. The company will continue the components of the Commission's legacy Storm Hardening Plan and will seek recovery of the costs associated with these activities through the SPPCRC, with the exception of the Geographical Information System, Post-Storm Data Collection, Increased Coordination with Local Governments, Disaster Preparedness and Recovery Plan, Distribution Pole Replacements, and unplanned (reactive) vegetation management.
13. The company would show with transparency the total costs for the proposed 2020-2029 SPP, the total revenue requirements for the proposed 2020-2029 SPP, and the total revenue requirements which would be recoverable through the Storm Protection Plan Cost Recovery Clause.

The table below provides Tampa Electric's projected 2020-2029 Storm Protection Plan total costs (capital and O&M) by Programs:

**Tampa Electric's 2020-2029 Storm Protection Plan Total Costs by Program (in Millions)**

| Capital | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Lateral Undergrounding | $8.00 | $79.45 | $108.08 | $101.44 | $107.00 | $110.78 | $113.96 | $111.42 | $115.52 | $121.17 | $976.81 |
| Transmission Asset Upgrades | $5.50 | $15.21 | $14.98 | $16.51 | $11.99 | $19.04 | $17.92 | $16.28 | $19.56 | $12.11 | $149.12 |
| Substation Extreme Weather Protection | $0.00 | $0.00 | $0.00 | $0.00 | $7.34 | $5.54 | $4.67 | $6.71 | $5.24 | $2.88 | $32.37 |
| Distribution Overhead Feeder Hardening | $6.50 | $15.38 | $29.58 | $33.39 | $32.49 | $33.19 | $33.82 | $32.76 | $36.36 | $36.25 | $289.73 |
| Transmission Access Enhancements | $0.00 | $1.38 | $1.52 | $1.56 | $1.66 | $1.40 | $0.54 | $3.17 | $1.93 | $1.57 | $14.73 |
| Distribution Pole Replacements | $9.42 | $11.18 | $14.72 | $15.16 | $15.62 | $16.09 | $10.64 | $10.86 | $11.07 | $11.29 | $126.05 |
| **O&M** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
| Distribution Vegetation Management - planned | $16.49 | $19.76 | $21.18 | $24.00 | $24.22 | $25.55 | $26.77 | $27.99 | $29.42 | $30.94 | $246.31 |
| Distribution Vegetation Management - unplanned | $1.30 | $1.30 | $1.20 | $1.10 | $1.10 | $1.10 | $1.20 | $1.20 | $1.30 | $1.30 | $12.10 |
| Transmission Vegetation Management - planned | $2.63 | $3.53 | $3.59 | $3.66 | $3.04 | $3.13 | $3.23 | $3.30 | $3.38 | $3.46 | $32.95 |
| Transmission Vegetation Management - unplanned | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Transmission Asset Upgrades | $0.11 | $0.30 | $0.30 | $0.33 | $0.24 | $0.38 | $0.36 | $0.33 | $0.39 | $0.24 | $2.98 |
| Distribution Overhead Feeder Hardening | $0.21 | $0.38 | $0.40 | $0.79 | $0.82 | $1.02 | $1.06 | $1.17 | $1.42 | $1.64 | $8.92 |
| Distribution Infrastructure Inspections | $0.71 | $1.00 | $1.02 | $1.04 | $1.06 | $1.08 | $1.10 | $1.13 | $1.15 | $1.17 | $10.46 |
| Transmission Infrastructure Inspections | $0.47 | $0.47 | $0.48 | $0.49 | $0.50 | $0.51 | $0.52 | $0.53 | $0.54 | $0.56 | $5.09 |
| SPP Planning & Common | $0.99 | $0.39 | $0.20 | $0.20 | $0.21 | $0.21 | $0.22 | $0.22 | $0.22 | $0.23 | $3.10 |
| Other Legacy Storm Hardening Plan Items | $0.28 | $0.28 | $0.29 | $0.29 | $0.30 | $0.30 | $0.31 | $0.32 | $0.32 | $0.33 | $3.01 |
| Distribution Pole Replacements | $0.52 | $0.62 | $0.81 | $0.83 | $0.86 | $0.88 | $0.59 | $0.60 | $0.61 | $0.62 | $6.93 |

Tampa Electric developed the 2020-2029 SPP projected costs and benefits for each of the proposed SPP Programs through the thorough and comprehensive analysis the company performed with Accenture LLP and 1898 & Co. Accenture, as described above, modeled the current VM Program against the proposed SPP initiatives during extreme weather. For the other SPP Programs, Tampa Electric worked with 1898 & Co. to evaluate the benefits of the 10-year Programs against a status quo scenario. Both the reduction in restoration costs and the reduction in customer minutes of interruption show the percentage improvement expected during major event days from the SPP Programs when compared to the status quo.

**Tampa Electric - Proposed 2020-2029 Storm Protection Plan Projected Costs versus Benefits**

| Storm Protection Program | Projected Costs (in Millions) | | Projected Reduction in Restoration Costs (Approximate Benefits in Percent) | Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent) | Program Start Date | Program End Date |
|---|---|---|---|---|---|---|
| | Capital | O&M | | | | |
| Distribution Lateral Undergrounding | $976.8 | $0.0 | 33 | 44 | Q2 2020 | After 2029 |
| Vegetation Management | $0.0 | $279.3 | 21 | 22 to 29 | Q2 2020 | After 2029 |
| Transmission Asset Upgrades | $148.9 | $3.0 | 90 | 13 | Q2 2020 | 2029 |
| Substation Extreme Weather | $32.4 | $0.0 | 70 to 80 | 50 to 65 | Q1 2021 | After 2029 |
| Distribution Overhead Feeder | $289.7 | $8.9 | 38 to 42 | 30 | Q2 2020 | After 2029 |
| Transmission Access Enhancements | $14.8 | $0.0 | 10 | 74 | Q1 2021 | After 2029 |

Tampa Electric developed the estimated annual jurisdictional revenue requirements with cost estimates for each of the proposed 2020-2029 SPP Programs plus depreciation and return on

SPP, as outlined in Rule 25-6.030 F.A.C. The estimated annual jurisdictional revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures using the depreciation rates from Tampa Electric's most current depreciation study. In addition, the depreciation expense has been reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the SPP capital Projects. Lastly, in accordance with the FPSC Order No. PSC-12-0425-PAA-EU, from the company's 2012 Stipulation and Settlement Agreement, Tampa Electric calculated a return on the undepreciated balance of the asset costs at a weighted average cost of capital using the return on equity from the May 2019 Actual Surveillance Report. Only capital expenditures for SPP Projects after April 10, 2020 were included in the depreciation and return on asset calculations included in the estimated annual jurisdictional revenue requirements.

The table below provides Tampa Electric's projected 2020-2029 Storm Protection Plan total revenue requirements (capital and O&M) by Program:

**Tampa Electric's 2020-2029 Storm Protection Plan Total Revenue Requirements by Program (in Millions)**

| Capital | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Lateral Undergrounding | $0.19 | $4.66 | $13.83 | $23.93 | $33.76 | $43.83 | $54.01 | $64.01 | $73.84 | $83.91 | $395.97 |
| Transmission Asset Upgrades | $0.14 | $1.25 | $2.69 | $4.16 | $5.45 | $6.82 | $8.45 | $9.91 | $11.40 | $12.66 | $62.93 |
| Substation Extreme Weather Protection | $0.00 | $0.00 | $0.00 | $0.00 | $0.28 | $0.95 | $1.42 | $1.93 | $2.47 | $2.82 | $9.87 |
| Distribution Overhead Feeder Hardening | $0.14 | $1.33 | $3.42 | $6.33 | $9.30 | $12.19 | $15.06 | $17.83 | $20.64 | $23.53 | $109.77 |
| Transmission Access Enhancements | $0.00 | $0.06 | $0.19 | $0.33 | $0.48 | $0.61 | $0.69 | $0.85 | $1.07 | $1.22 | $5.50 |
| Distribution Pole Replacements | $0.25 | $1.41 | $2.60 | $3.96 | $5.32 | $6.69 | $7.79 | $8.61 | $9.42 | $10.22 | $56.27 |
| **O&M** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
| Distribution Vegetation Management - planned | $16.49 | $19.76 | $21.18 | $24.00 | $24.22 | $25.55 | $26.77 | $27.99 | $29.42 | $30.94 | $246.31 |
| Distribution Vegetation Management - unplanned | $1.30 | $1.30 | $1.20 | $1.10 | $1.10 | $1.10 | $1.20 | $1.20 | $1.30 | $1.30 | $12.10 |
| Transmission Vegetation Management - planned | $2.63 | $3.53 | $3.59 | $3.66 | $3.04 | $3.13 | $3.23 | $3.30 | $3.38 | $3.46 | $32.95 |
| Transmission Vegetation Management - unplanned | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Transmission Asset Upgrades | $0.11 | $0.30 | $0.30 | $0.33 | $0.24 | $0.38 | $0.36 | $0.33 | $0.39 | $0.24 | $2.98 |
| Distribution Overhead Feeder Hardening | $0.21 | $0.38 | $0.40 | $0.79 | $0.82 | $1.02 | $1.06 | $1.17 | $1.42 | $1.64 | $8.92 |
| Distribution Infrastructure Inspections | $0.71 | $1.00 | $1.02 | $1.04 | $1.06 | $1.08 | $1.10 | $1.13 | $1.15 | $1.17 | $10.46 |
| Transmission Infrastructure Inspections | $0.47 | $0.47 | $0.48 | $0.49 | $0.50 | $0.51 | $0.52 | $0.53 | $0.54 | $0.56 | $5.09 |
| SPP Planning & Common | $0.99 | $0.39 | $0.20 | $0.20 | $0.21 | $0.21 | $0.22 | $0.22 | $0.22 | $0.23 | $3.10 |
| Other Legacy Storm Hardening Plan Items | $0.28 | $0.28 | $0.29 | $0.29 | $0.30 | $0.30 | $0.31 | $0.32 | $0.32 | $0.33 | $3.01 |
| Distribution Pole Replacements | $0.52 | $0.62 | $0.81 | $0.83 | $0.86 | $0.88 | $0.59 | $0.60 | $0.61 | $0.62 | $6.93 |

# 8 Storm Protection Plan Estimated Rate Impacts

Tampa Electric prepared estimated rate impacts of the Storm Protection Plan for 2020, 2021, 2022 and 2023. While there are not going to be any billed rate impacts during 2020, the 2020 costs have been calculated separately from the 2021 costs so the impact of each year on the 2021 rate impacts is clear. This is because the 2020 costs will be recovered at the same time as the 2021 costs through the Storm Protection Plan Cost Recovery Clause ("SPPCRC") rates initiating in January 2021.

Each year's costs derive from the SPP Programs described in this Plan and are the capital and O&M costs combined into a revenue requirement. For each year, the SPP Programs were itemized and identified as to whether they are substation, transmission or distribution costs. Each of those functionalized costs were then allocated to the appropriate rate class using the allocation factors for that function.

The allocation factors used were from the Tampa Electric's 2013 Cost of Service Study prepared in Docket No. 20130040-EI which was used for the current company's base rate design. Using these factors assures that the incremental SPP costs are being recovered from customers in the same manner as the comparable costs included in base rates are being recovered through current base rates.

Once the total SPP revenue requirement recovery allocation to the rate classes was derived, the clause rates were determined in the same manner as current clause rates are designed.

For Residential, the charge is a kWh charge. For both Commercial and Industrial, the charge is a kW charge. The charges are derived by dividing the rate class allocated SPP revenue requirements by the most recent 2020 energy billing determinants (for residential) and by the most recent 2020 demand billing determinants (for commercial and industrial). Those clause charges were then applied to the billing determinants associated with typical bills for those groups to calculate the impact on those bills. This was done using a combination of 2020 and 2021 costs for the 2021 bills, and for each year 2022 and 2023 for those bills.

A similar procedure will be used to derive actual clause charges in the clause cost recovery docket to come this summer, but in that case applied to all rate classes and using 2021 projected billing determinants.

The following table shows the full rate impact of the SPP on typical bills:

| | **Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)** | | | |
|---|---|---|---|---|
| | **Customer Class** | | | |
| | Residential 1000 kWh | Residential 1250 kWh | Commercial 1 MW 60 percent Load Factor | Industrial 10 MW 60 percent Load Factor |
| 2020 | 1.50 | 1.48 | 1.44 | 0.55 |
| 2021 | 2.22 | 2.21 | 2.14 | 0.84 |
| 2022 | 3.09 | 3.06 | 2.98 | 1.13 |
| 2023 | 4.12 | 4.07 | 3.95 | 1.46 |

The rate impacts presented above reflect the total cost of the SPP, even though some of the costs in the Plan are currently being recovered through base rates and the incremental cost of the Plan to customers will be less than shown above. For example, using the average of the certain actual storm hardening costs reflected in the company’s operation and maintenance expenses for 2017, 2018 and 2019 as a proxy, Tampa Electric estimates that the revenue requirement associated with amount of SPP O&M expenses currently being recovered through base rates is approximately $12.9 million.

# 9 Storm Protection Plan Alternatives and Considerations

Tampa Electric considered several "implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the plan" as required by Rule 25-6.030(3)(i).

The company started the development of the proposed SPP by briefly considering a "do nothing" scenario that would have resulted in no incremental investments in the transmission and distribution systems. This initial discussion was based upon on the company's historical performance and the current ongoing Storm Hardening Plan Initiatives. This alternative was good for level setting in that it identified the analyses that would be performed would need to examine the entire service area for opportunities for enhancement. In addition, this alternative was quickly dismissed as the statute is clear in that it requires all Florida investor owned utilities to submit a storm plan with the express purpose of hardening the system to reduce outage restoration costs and outage times. The statute emphasizes vegetation management, overhead hardening, and the undergrounding of overhead distribution lines, so the company began its planning with these activities at the forefront.

As described in the overview, the company engaged Accenture to evaluate several initiatives to enhance existing vegetation management plans and performance. As part of this analysis, several increments of activity and spending were evaluated. The company selected the option that yielded the most customer benefits.

Tampa Electric and 1898 & Co. used the resilience-based planning approach to establish an overall capital budget level and to identify and prioritize resilience investment in the company's T&D system. The budget optimization analysis was performed in $250 million increments up to $2.5 billion. The analysis showed 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. The company's overall investment level is right before the point of diminishing returns, which demonstrates that Tampa Electric's SPP has an appropriate level of investment over the 2020-2029 ten-year period capturing the Storm Protection Projects that provide the most value to customers.

In addition to the Programs included in the 2020-2029 SPP, Tampa Electric evaluated other capital Programs and Projects for inclusion in the Plan. Examples of things considered, but not included in this initial ten-year SPP are as follows:

- Undergrounding Distribution Feeders – The majority of customers are on laterals and analysis demonstrated higher cost-benefit to harden feeders and underground laterals.
- Upgrading wood distribution poles to non-wood materials – The company will continue to evaluate this option as manufacturing capabilities improve. At this time, the upgraded wood materials provide the best cost-benefit ratio for customers.
- Purchasing additional temporary access solutions such as increasing the number of mats – The solutions proposed in this Plan are more cost-effective and sustainable

As in the past with the company's prior Storm Hardening Plan Initiatives, Tampa Electric will also examine and analyze the processes and procedures used to implement the company's proposed 2020-2029 SPP Programs for any ongoing continuous improvement opportunities. This examination will assist in mitigating the resulting rate impact and ensure the benefits from the proposed SPP are realized.

# Tampa Electric's

# 2020–2029

# Storm Protection Plan

# Appendices

# Appendix A
# Project Detail
# Distribution Lateral Undergrounding

**Tampa Electric's Distribution Lateral Undergrounding - Year 2020 Details**

| Project ID | Circuit No. | Specific Project Detail | | Customers | | | | Priority Customers | Project Start Qtr | Construction | | Project Cost in 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | OH to UG Length Converted (miles) | Poles | Residential | Small C&I | Large C&I | Total | | | Start Qtr | End Qtr | |
| Lateral Hardening-Fuse-60588225 | 13174 | 0.29 | 15 | 374 | 34 | 1 | 409 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $125,235 |
| Lateral Hardening-Fuse-10786382 | 14040 | 0.23 | 13 | 98 | 6 | 2 | 106 | 10 | Q2 2020 | Q3 2020 | Q4 2020 | $150,431 |
| Lateral Hardening-Fuse-90755954 | 13454 | 0.30 | 23 | 292 | 21 | 1 | 314 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $238,629 |
| Lateral Hardening-Fuse-60451701 | 13174 | 0.24 | 14 | 301 | 11 | 2 | 314 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $230,114 |
| Lateral Hardening-Fuse-10933151 | 13897 | 0.79 | 33 | 64 | 20 | 1 | 85 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $221,051 |
| Lateral Hardening-Fuse-92421291 | 13972 | 0.44 | 23 | 379 | 6 | 1 | 386 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $248,973 |
| Lateral Hardening-Fuse-92881445 | 13710 | 0.45 | 32 | 158 | 17 | 0 | 175 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $401,397 |
| Lateral Hardening-Fuse-92599119 | 13390 | 0.72 | 46 | 266 | 27 | 3 | 296 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $750,732 |
| Lateral Hardening-Fuse-92407065 | 13815 | 0.38 | 15 | 12 | 3 | 1 | 16 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $68,399 |
| Lateral Hardening-Fuse-93019714 | 13840 | 0.13 | 9 | 39 | 2 | 0 | 41 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $51,112 |
| Lateral Hardening-Fuse-92634300 | 14032 | 0.31 | 21 | 306 | 10 | 2 | 318 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $390,745 |
| Lateral Hardening-Fuse-60287236 | 13509 | 0.15 | 14 | 144 | 14 | 0 | 158 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $175,078 |
| Lateral Hardening-Fuse-60182741 | 13312 | 0.15 | 15 | 52 | 11 | 7 | 70 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $101,387 |
| Lateral Hardening-Fuse-90241880 | 13972 | 0.90 | 49 | 130 | 7 | 6 | 143 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $687,129 |
| Lateral Hardening-Fuse-10643541 | 13390 | 1.17 | 67 | 221 | 22 | 2 | 245 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $1,095,650 |
| Lateral Hardening-Fuse-10786374 | 14040 | 0.27 | 16 | 205 | 13 | 0 | 218 | 11 | Q2 2020 | Q3 2020 | Q4 2020 | $334,434 |
| Lateral Hardening-Fuse-92829453 | 13961 | 0.34 | 25 | 447 | 3 | 2 | 452 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $292,496 |
| Lateral Hardening-Fuse-91406672 | 13836 | 0.35 | 25 | 91 | 6 | 0 | 97 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $248,786 |
| Lateral Hardening-Fuse-90288627 | 13815 | 0.88 | 32 | 51 | 9 | 0 | 60 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $423,948 |
| Lateral Hardening-Fuse-91432109 | 13071 | 0.14 | 15 | 20 | 5 | 0 | 25 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $163,279 |
| Lateral Hardening-Fuse-90738378 | 13071 | 0.16 | 20 | 296 | 35 | 0 | 331 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $145,327 |
| Lateral Hardening-Fuse-90911087 | 13724 | 0.54 | 32 | 31 | 4 | 0 | 35 | 6 | Q2 2020 | Q3 2020 | Q4 2020 | $423,395 |
| Lateral Hardening-Fuse-93026469 | 13815 | 0.49 | 15 | 27 | 2 | 0 | 29 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $375,085 |
| Lateral Hardening-Fuse-10629014 | 13146 | 0.54 | 30 | 91 | 6 | 0 | 97 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $608,468 |

# Appendix B

# Project Detail

# Transmission Asset Upgrades

| Tampa Electric's Transmission Asset Upgrades - Year 2020 Details | | | | | | |
|---|---|---|---|---|---|---|
| Project ID | Circuit No. | Pole Count | Project Start Month | Construction Start Month | Construction End Month | Project Cost in 2020 |
| Transmission Upgrades-69 kV-66654 | 66654 | 10 | May-20 | Jul-20 | Jul-20 | $317,000 |
| Transmission Upgrades-69 kV-66840 | 66840 | 34 | May-20 | Jul-20 | Aug-20 | $1,077,800 |
| Transmission Upgrades-69 kV-66007 | 66007 | 43 | Jun-20 | Aug-20 | Aug-20 | $1,363,100 |
| Transmission Upgrades-69 kV-66019 | 66019 | 21 | Jul-20 | Sep-20 | Oct-20 | $665,700 |
| Transmission Upgrades-69 kV-66425 | 66425 | 3 | Jul-20 | Oct-20 | Oct-20 | $95,100 |
| Transmission Upgrades-138/230 kV-230403 | 230403 | 5 | Jul-20 | Oct-20 | Oct-20 | $105,700 |
| Transmission Upgrades-69 kV-66413 | 66413 | 5 | Jul-20 | Oct-20 | Oct-20 | $158,500 |
| Transmission Upgrades-69 kV-66046 | 66046 | 30 | Jul-20 | Oct-20 | Nov-20 | $939,900 |
| Transmission Upgrades-69 kV-66059 | 66059 | 2 | Aug-20 | Nov-20 | Nov-20 | $63,400 |
| Transmission Upgrades-138/230 kV-230008 | 230008 | 59 | Aug-20 | Nov-20 | Jan-21 | $700,150 |
| Transmission Upgrades-138/230 kV-230010 | 230010 | 2 | Sep-20 | Jan-21 | Jan-21 | $900 |
| Transmission Upgrades-138/230 kV-230038 | 230038 | 1 | Oct-20 | Jan-21 | Jan-21 | $450 |
| Transmission Upgrades-138/230 kV-230003 | 230003 | 35 | Oct-20 | Jan-21 | Feb-21 | $15,750 |
| Transmission Upgrades-138/230 kV-230005 | 230005 | 24 | Oct-20 | Feb-21 | Feb-21 | $10,800 |
| Transmission Upgrades-138/230 kV-230004 | 230004 | 40 | Nov-20 | Feb-21 | Mar-21 | $18,000 |
| Transmission Upgrades-138/230 kV-230625 | 230625 | 12 | Nov-20 | Mar-21 | Mar-21 | $5,400 |
| Transmission Upgrades-138/230 kV-230021 | 230021 | 17 | Nov-20 | Mar-21 | Apr-21 | $7,650 |
| Transmission Upgrades-138/230 kV-230052 | 230052 | 9 | Dec-20 | Apr-21 | Apr-21 | $2,700 |
| Transmission Upgrades-69 kV-66024 | 66024 | 25 | Dec-20 | Apr-21 | Apr-21 | $27,750 |
| Transmission Upgrades-138/230 kV-230608 | 230608 | 18 | Dec-20 | May-21 | May-21 | $7,200 |
| Transmission Upgrades-138/230 kV-230603 | 230603 | 13 | Dec-20 | May-21 | May-21 | $1,800 |

The North American Electric Reliability Corporation ("NERC") defines the transmission system as lines operated at relatively high voltages varying from 69kV up to 765kV and capable of delivery large quantities of electricity. Tampa Electric's transmission system is made up of 69kV, 138kV and 230kV voltages and is designed to transmit power to the end-user 13.2kV distribution substations. As such, Tampa Electric does not attribute customer counts directly to individual transmission lines. It should be noted, that without Tampa Electric's transmission network in place, power could not be delivered to the distribution network which would result in automatic load loss.

# Appendix C

# Project Detail

# Substation Extreme Weather Hardening

**Reserved for Future Use**

# Appendix D

# Project Detail

# Distribution Overhead Feeder Hardening

## Tampa Electric's Distribution Overhead Feeder Hardening - Year 2020 Details

| Project ID | Circuit No. | Specific Project Detail | Customers | | | | Priority Customers | Project Start Month | Construction | | Project Cost in 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Residential | Small C&I | Large C&I | Total | | | Start Month | End Month | |
| Distribution Feeder Hardening-Breaker-60067752 | 13308 | Tampa Electric will install (6) new reclosers, replace (3) existing manual switches with (3) reclosers, (45) fuses, (27) trip savers, and upgrade (52) feeder poles | 1,220 | 260 | 36 | 1,516 | 26 | May-20 | Aug-20 | Dec-20 | $1,153,700 |
| Distribution Feeder Hardening-Breaker-60095496-Recloser-92203202 | 13807 | Tampa Electric will install (8) new reclosers,(194) fuses, (40) trip savers, and upgrade (86) feeder poles | 1,159 | 103 | 16 | 1,278 | 12 | May-20 | Aug-20 | Dec-20 | $1,679,500 |
| Distribution Feeder Hardening-Breaker-60315127-Recloser-92189137 | 13805 | Tampa Electric will install (4) new reclosers, (202) fuses, (37) trip savers, and upgrade (93) feeder poles | 356 | 61 | 4 | 421 | 0 | May-20 | Aug-20 | Dec-20 | $1,565,900 |
| Distribution Feeder Hardening-Breaker-60066445 | 13745 | Tampa Electric will install (11) reclosers, (38) fuses, (10) trip savers, and upgrade (31) feeder poles | 3,106 | 242 | 50 | 3,398 | 62 | May-20 | Aug-20 | Dec-20 | $833,150 |
| Distribution Feeder Hardening-Breaker-60064337 | 13533 | Tampa Electric will install (13) reclosers, (42) fuses, (5) trip savers, upgraded breaker relays, and upgrade (33) feeder poles | 2,161 | 235 | 36 | 2,432 | 34 | May-20 | Aug-20 | Dec-20 | $1,044,300 |

# Appendix E

# Project Detail

# Transmission Access Enhancement

**Reserved for Future Use**

# Appendix F

# 1898 & Co, Tampa Electric's Storm Protection Plan Resilience Benefits Report

1898 & CO.
PART OF BURNS & McDONNELL

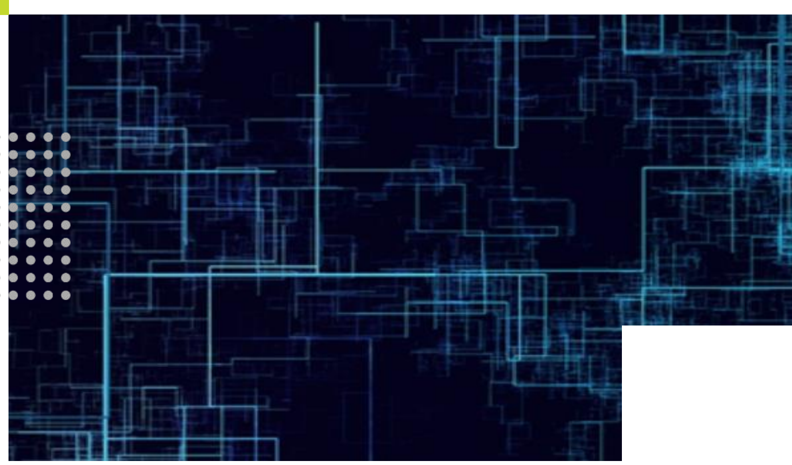
# Storm Protection Plan Resilience Benefits Report

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

## 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 |

| 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 |

# 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:

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

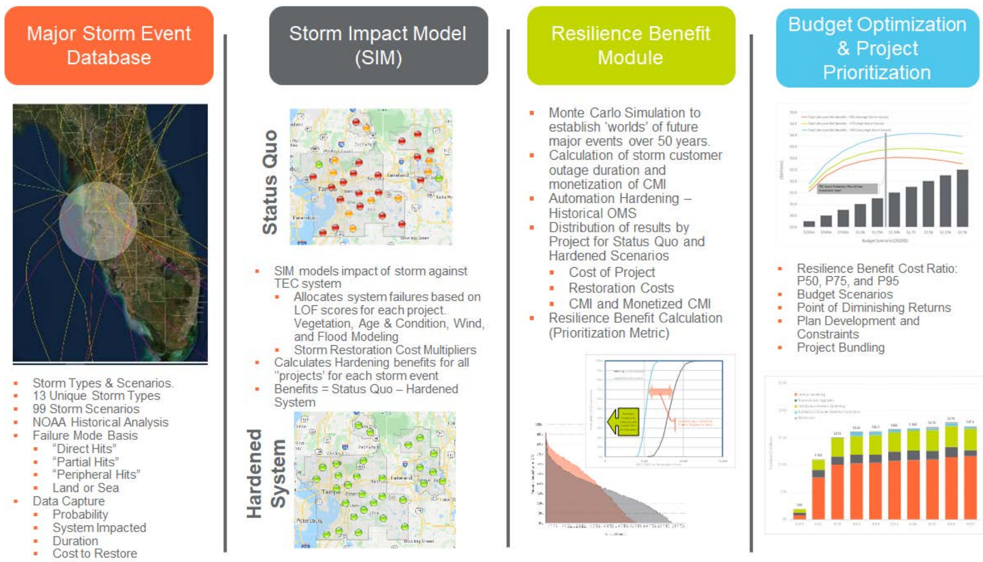
The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Replacements, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits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

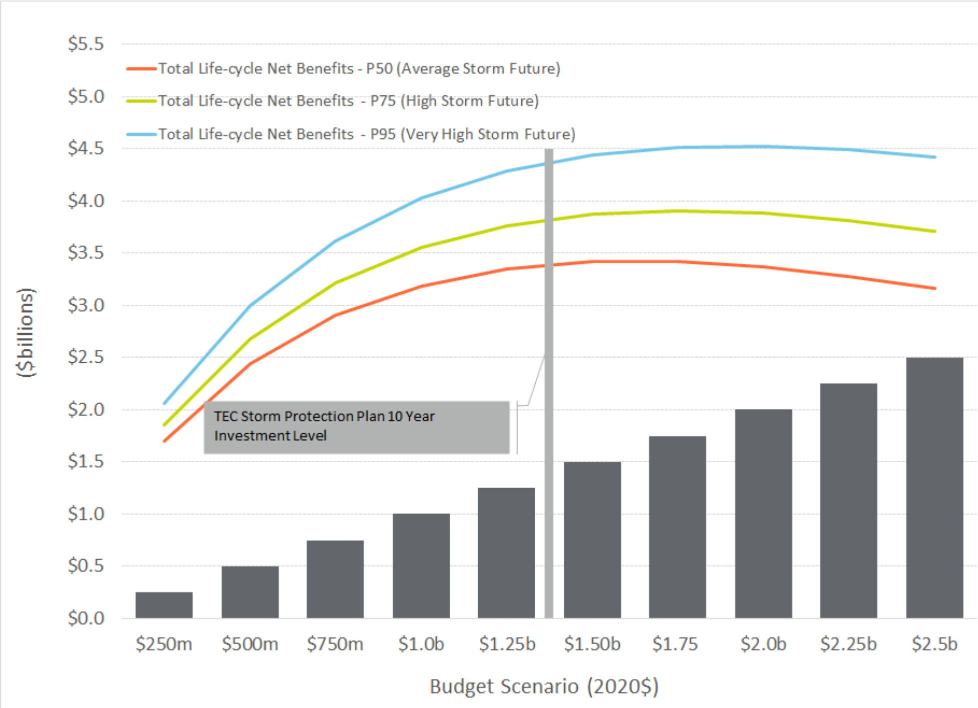
The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest resilience benefit cost ratio. It also performs a budget optimization over a range of budget levels to identify the point of diminishing returns.

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.

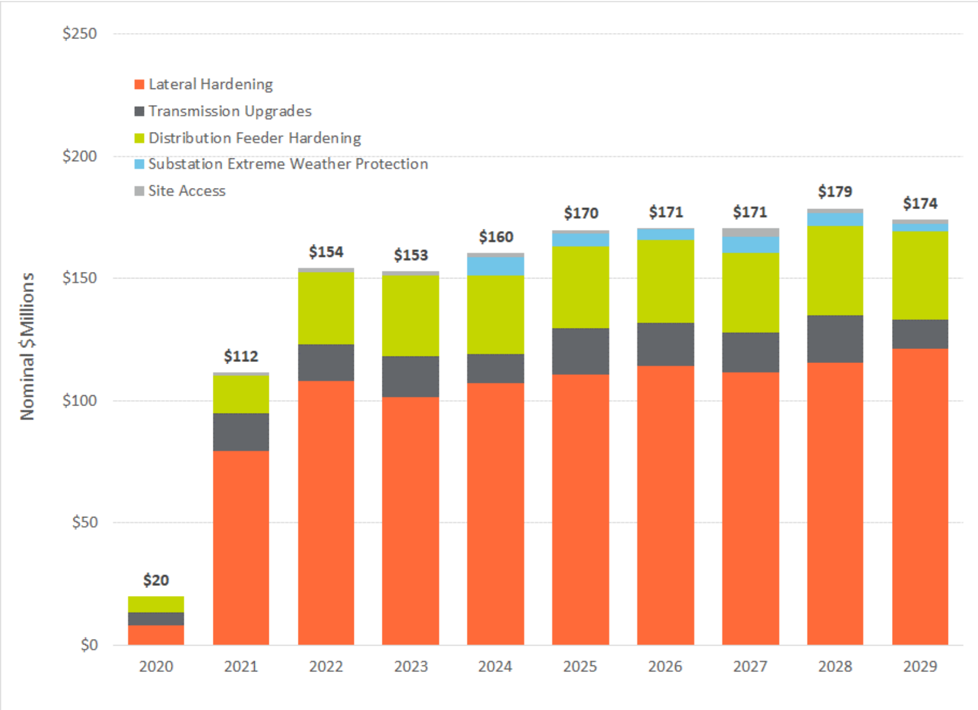
**Figure 1-2: Budget Optimization Results**




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**

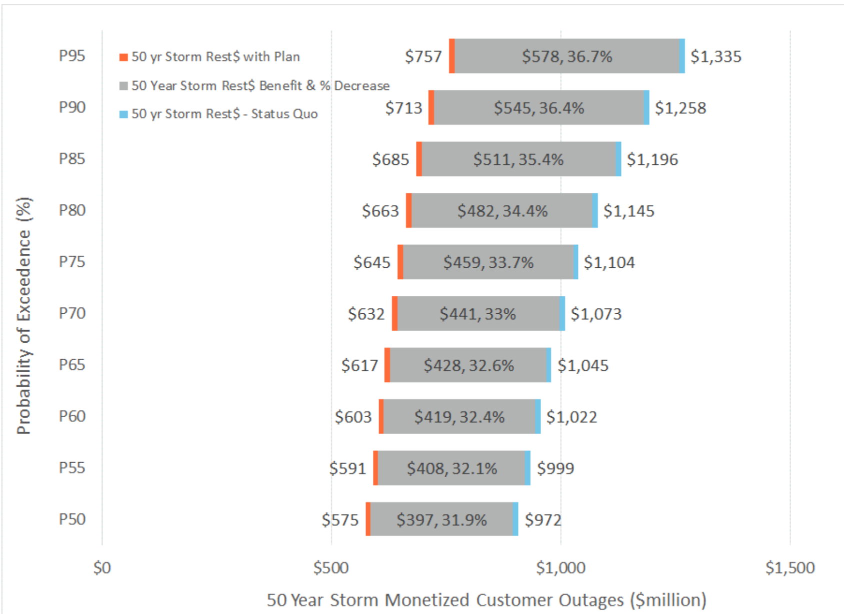



Customer benefits are calculated in terms of the:

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.

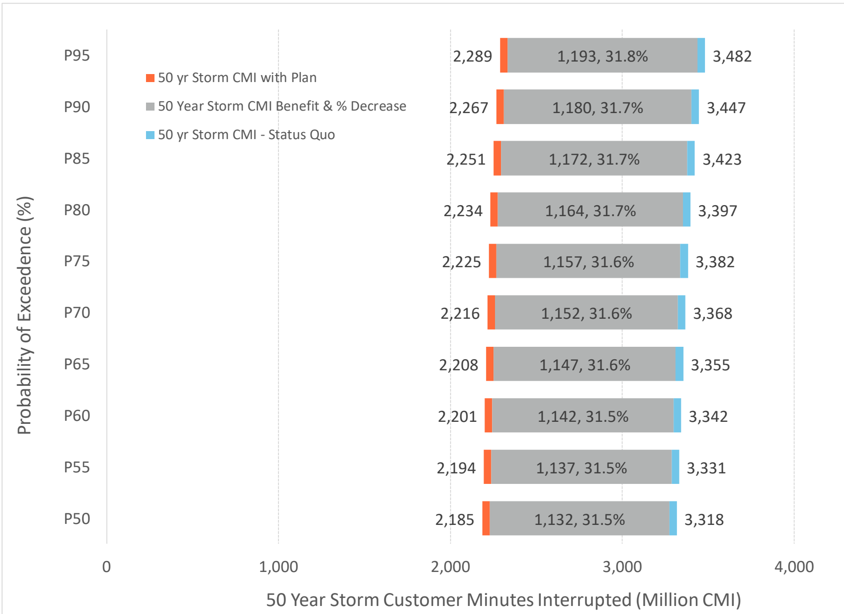
**Figure 1-4: Storm Protection Plan Restoration Cost Benefit**




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.

- 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.

## 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

- 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

> *"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.

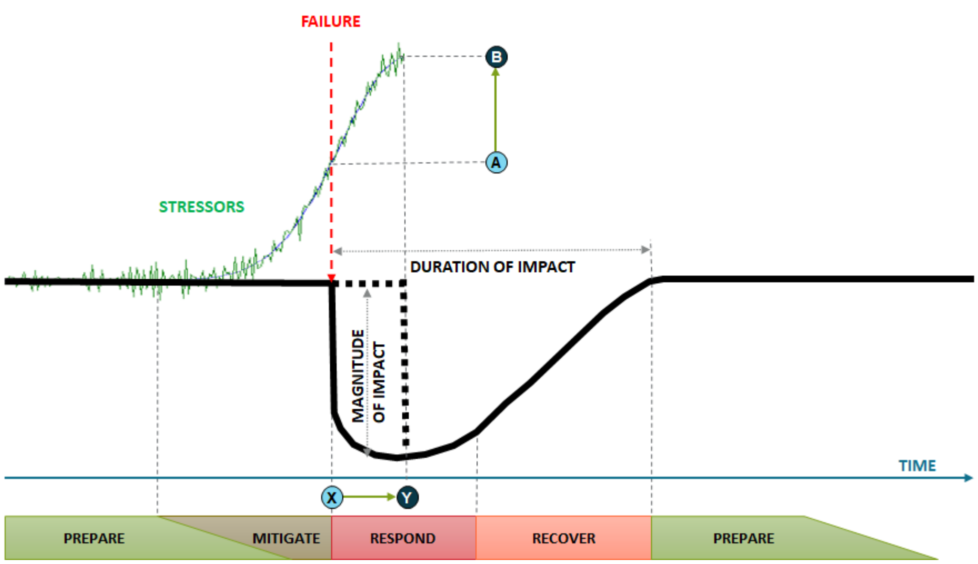
- Prepare (Before)
  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.
- Respond (During)
  The 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

(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.

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]** | **216** |
| **Site Access** | **[count]** | **96** |
| Roads | [count] | 70 |
| Bridges | [count] | 26 |

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.

#### 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.

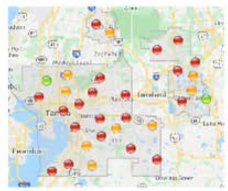
**Figure 2-2: Resilience Planning Approach Overview**

**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

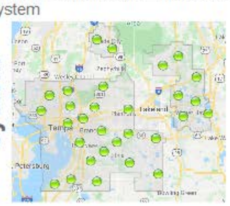
**Storm Impact Model (SIM)**

Status Quo



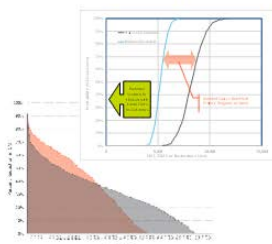
- SIM models impact of storm against TEC system
  - Allocates system failures based on LOF scores for each project. Vegetation, Age & Condition, Wind, and Flood Modeling
  - Storm Restoration Cost Multipliers
- Calculates Hardening benefits for all "projects' for each storm event
- Benefits = Status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

Hardened System

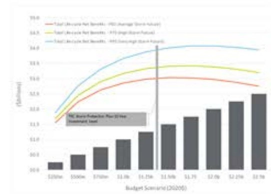


**Resilience Benefit Module**

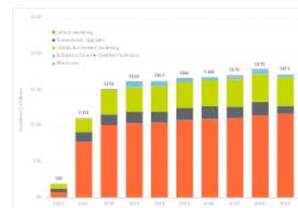
- Monte Carlo Simulation to establish 'worlds' of future major events over 50 years.
- Calculation of storm customer outage duration and monetization of CMI
- Automation Hardening – Historical OMS
- Distribution of results by Project for Status Quo and Hardened Scenarios
  - Cost of Project
  - Restoration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



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 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.

### 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.

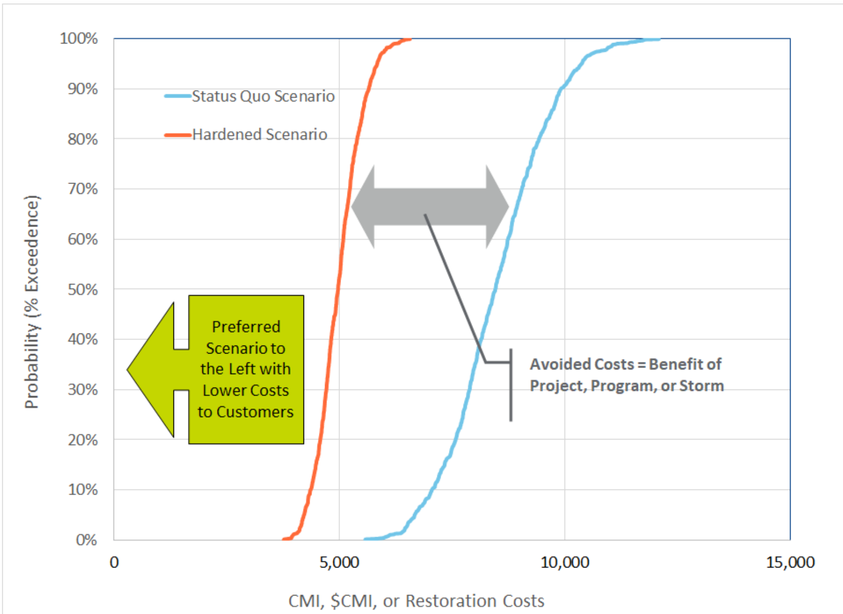
The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and 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**

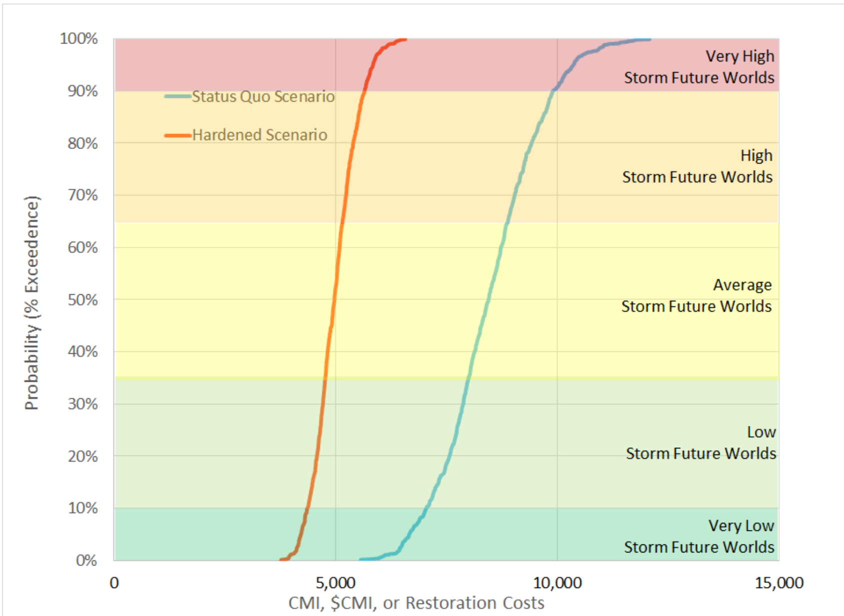



The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is 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.

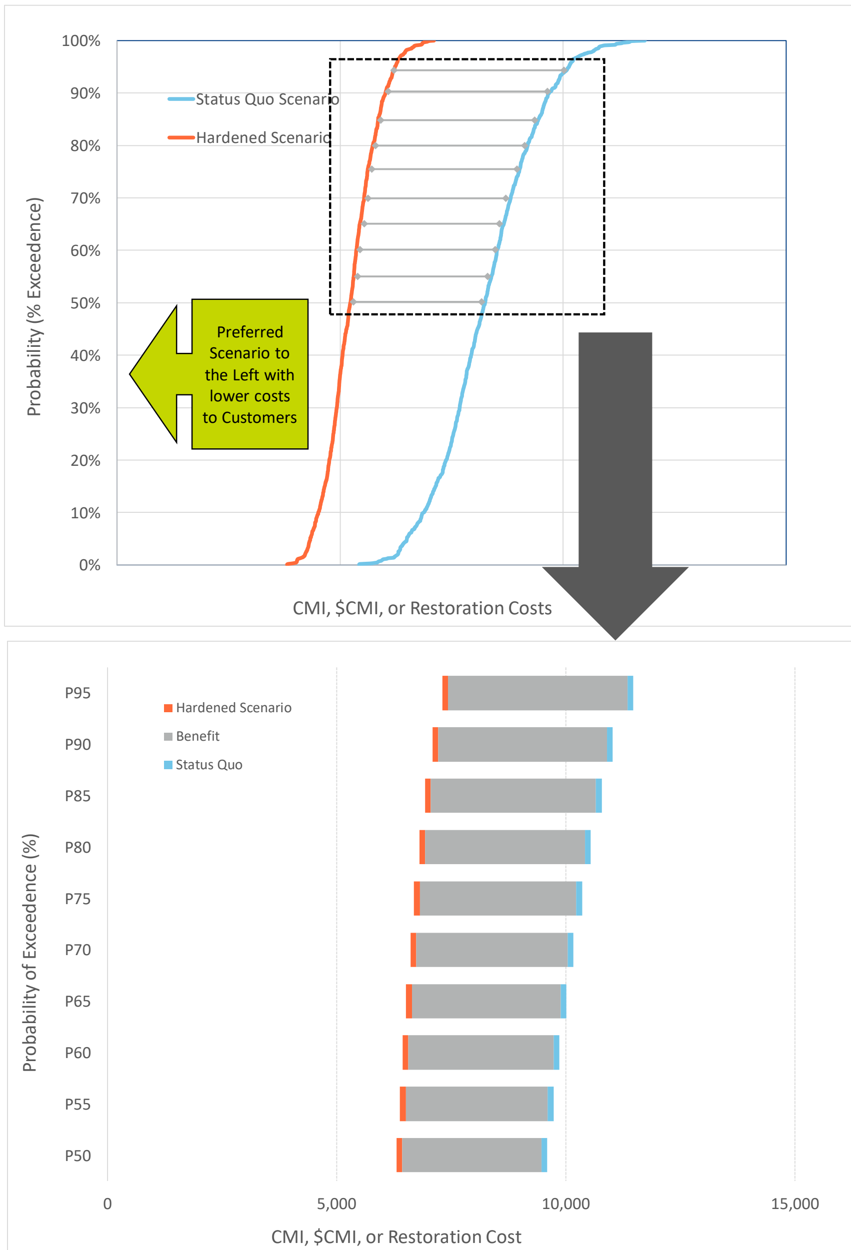
The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e. vertical) the less range in the result. The more horizontal the slope 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.

**Figure 2-5: S-Curves and Resilience Focus**



# 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:

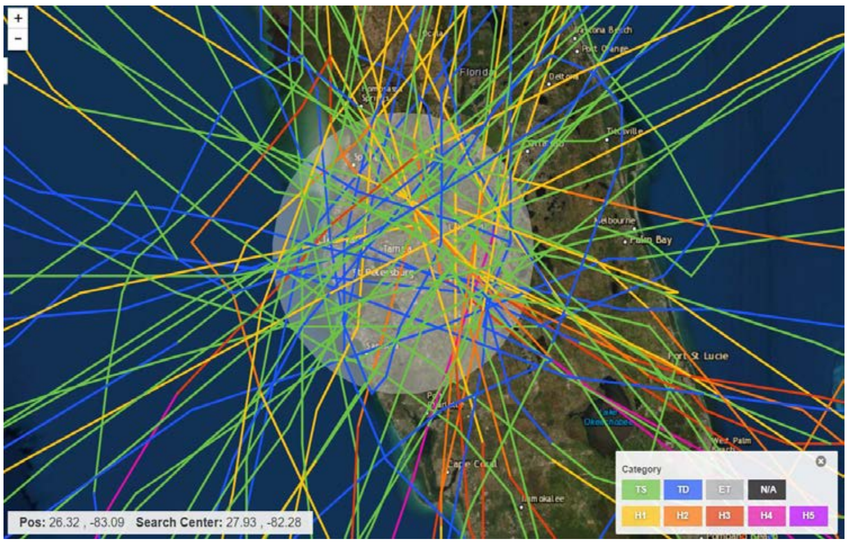
- Wind speeds of the storm (i.e. category of storm). Higher wind speeds means more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can 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 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]**

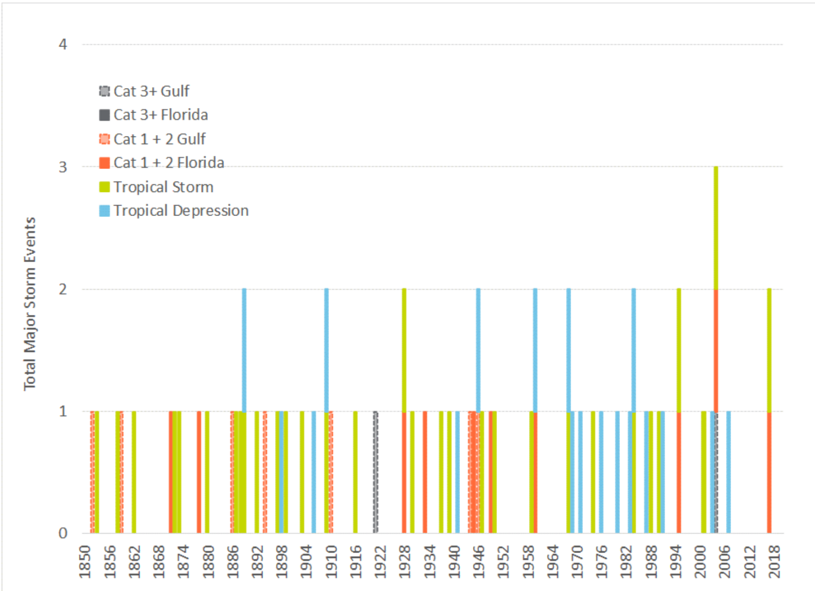



Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Direct Hits' over the time horizon. The figure shows a relative stability in the number of Category 1 and above storms over 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]**

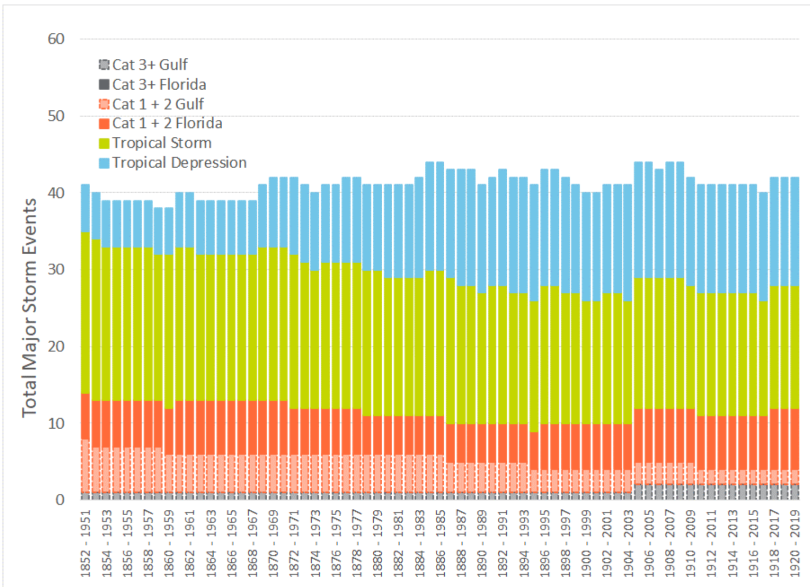
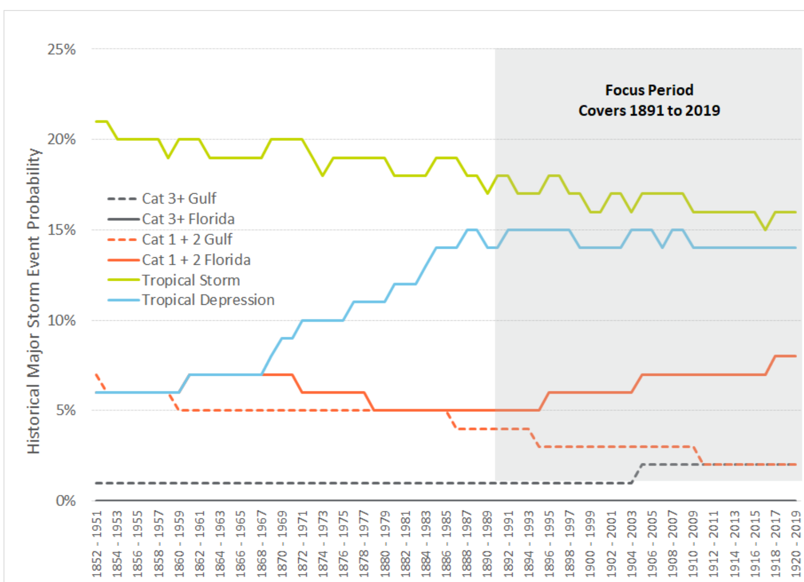



**Figure 3-4: "Direct Hits" (50 Miles) 100 Year Rolling Probability[3]**




[3] See Footnote 2

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]**

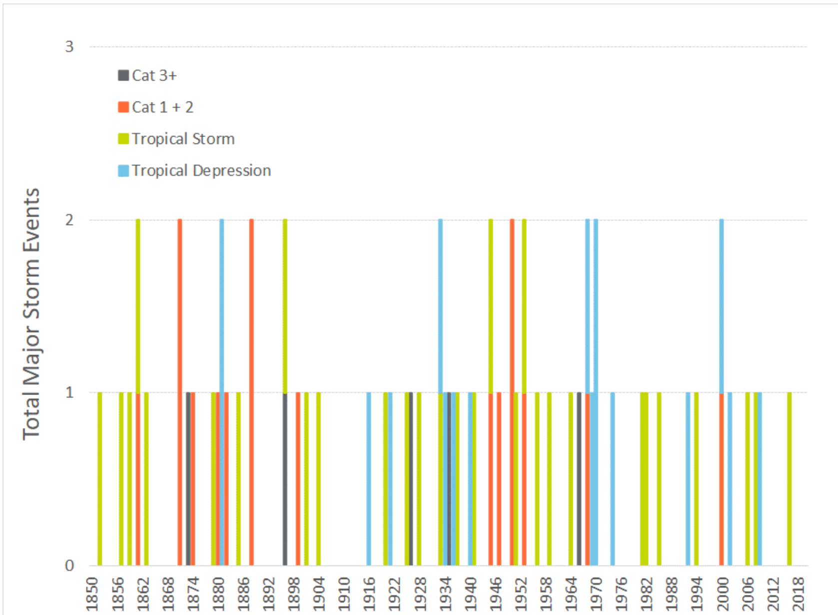



Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over 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]**

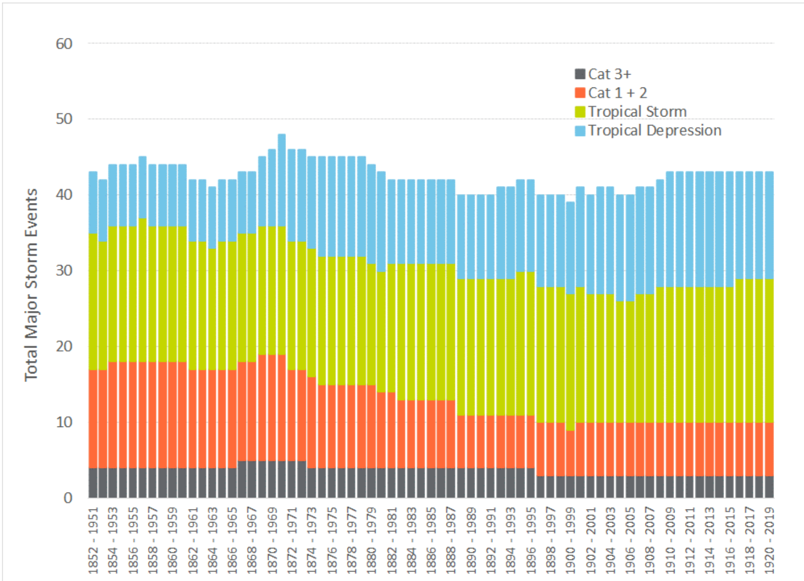
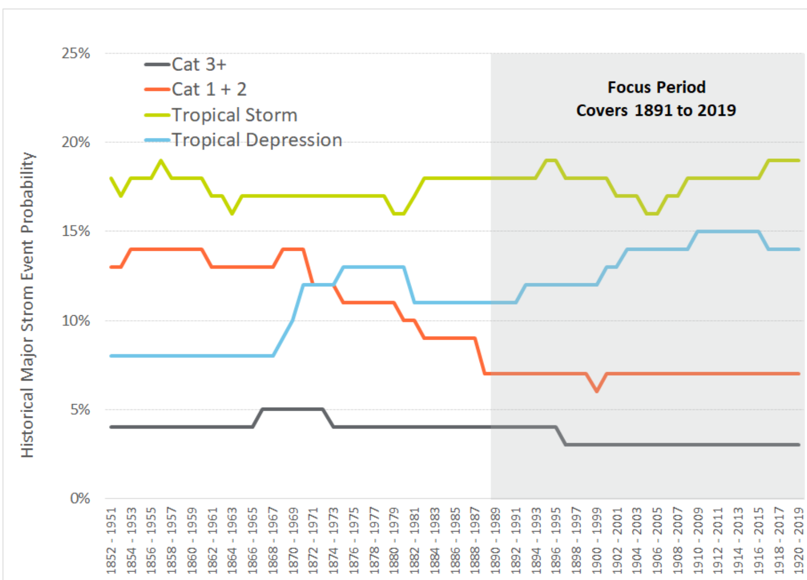



**Figure 3-7: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[5]**

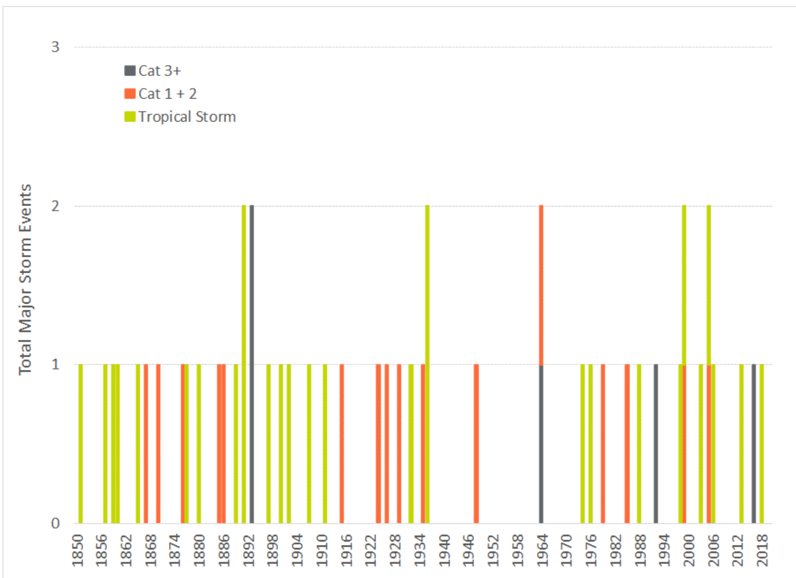



[5] See Footnote 2

### 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]**

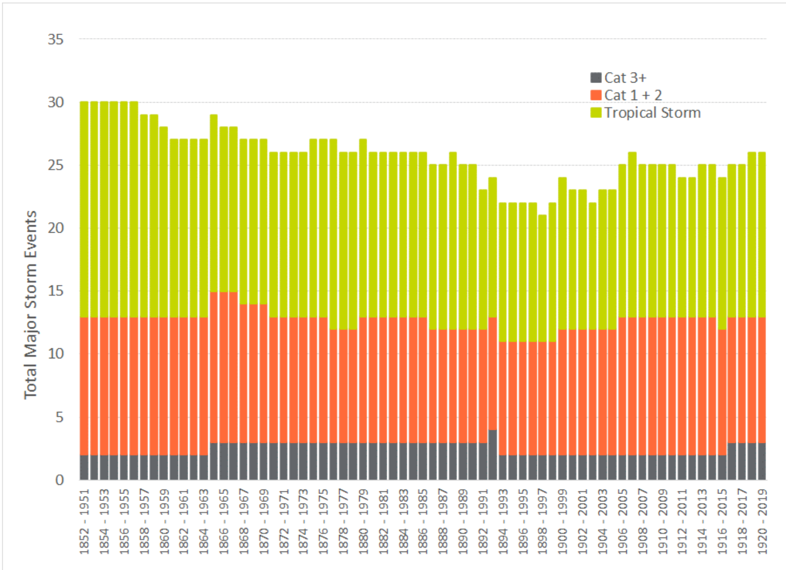
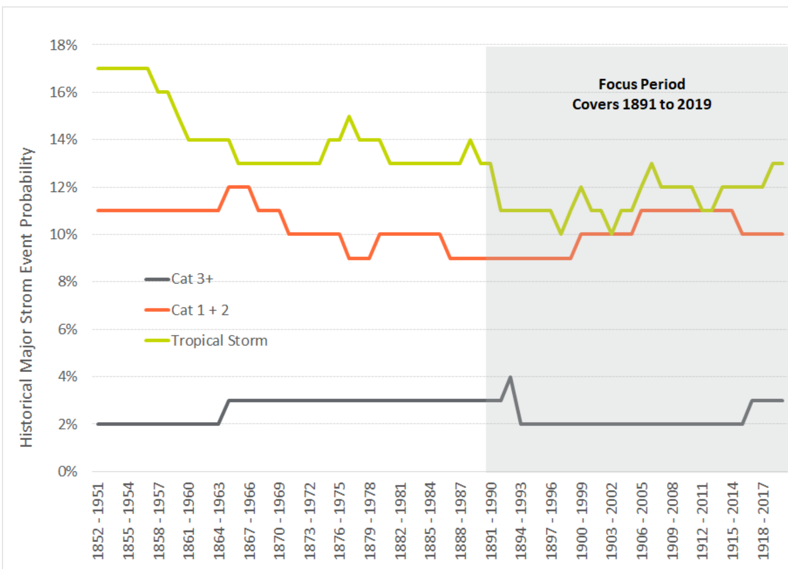



**Figure 3-10: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[7]**




[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**

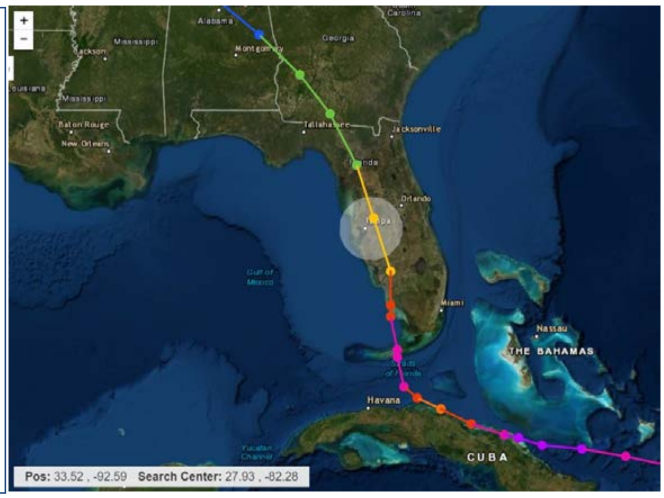



**Table 3-3: Storm Report Summary**

| 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 |

# 4.0 STORM IMPACT MODEL

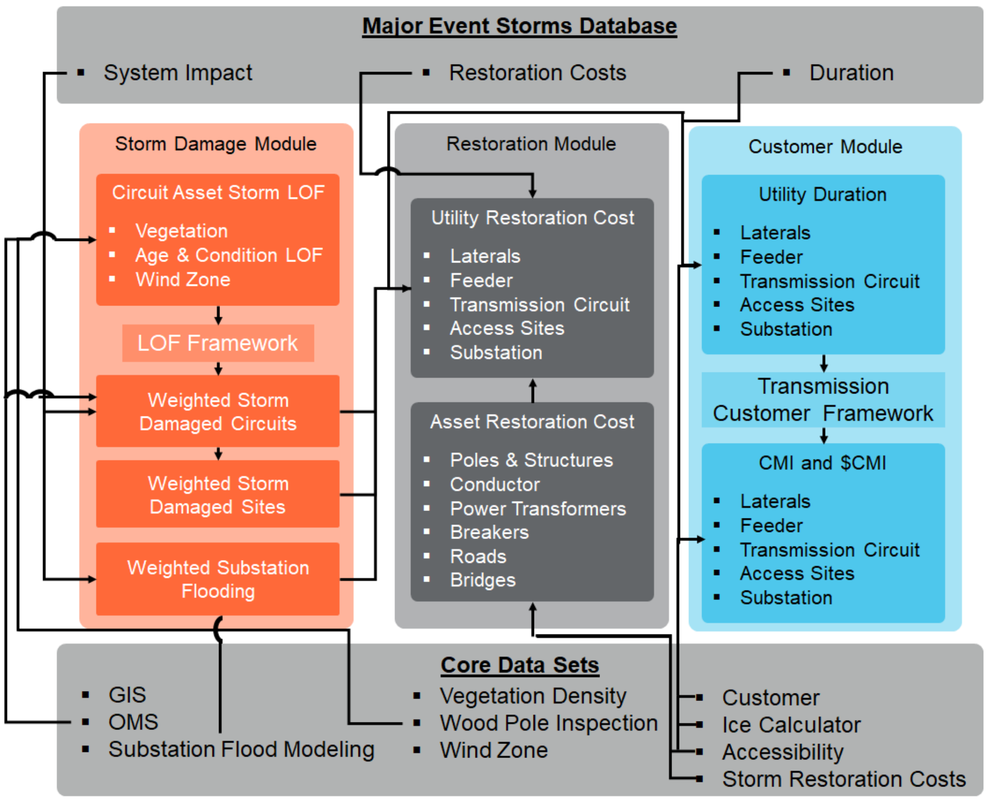
The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storms Event Database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for each storm stressor, the Storm Impact Model goes a layer deeper and develops the phases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

**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 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] | **216** |

**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.

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**

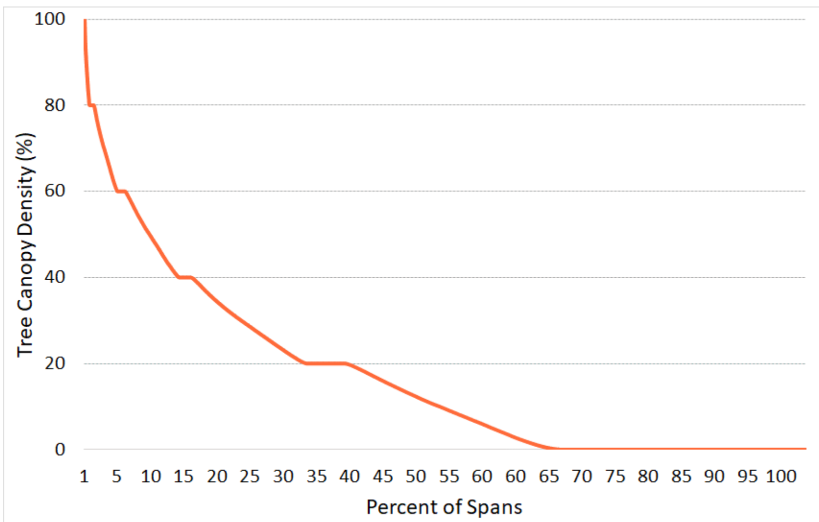
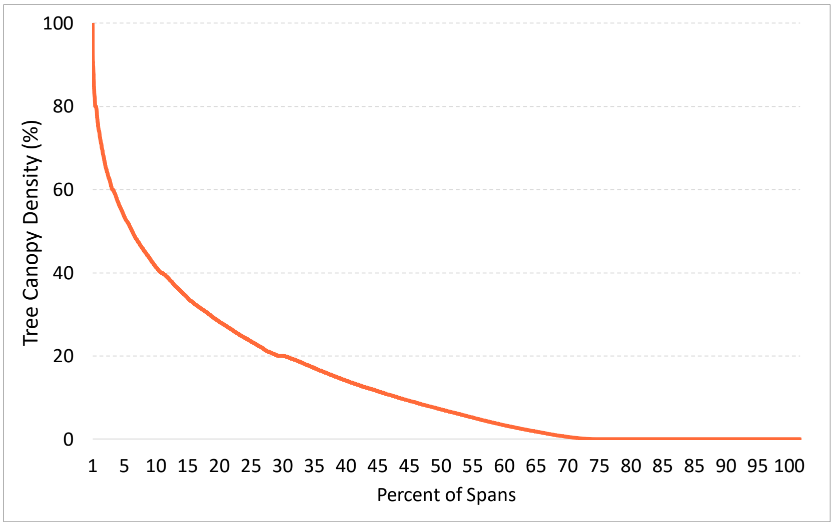


**Figure 4-3: Vegetation Density on TEC Transmission Conductor**

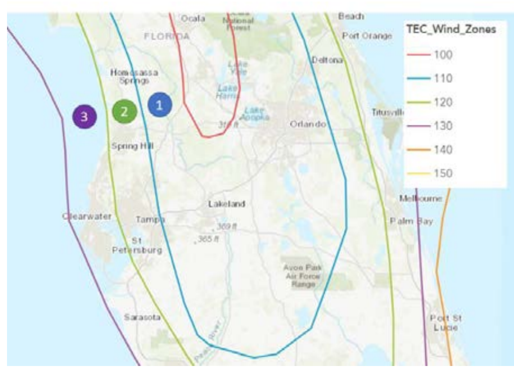



### 4.1.5 Wood Pole Inspection Data

A compromised, or semi-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.

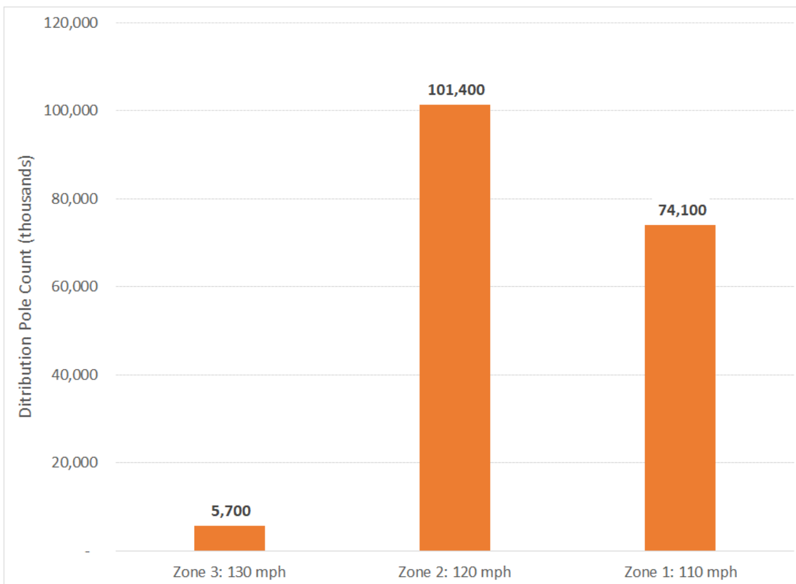
### 4.1.6 Wind Zone

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 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.

### 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.

### 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.

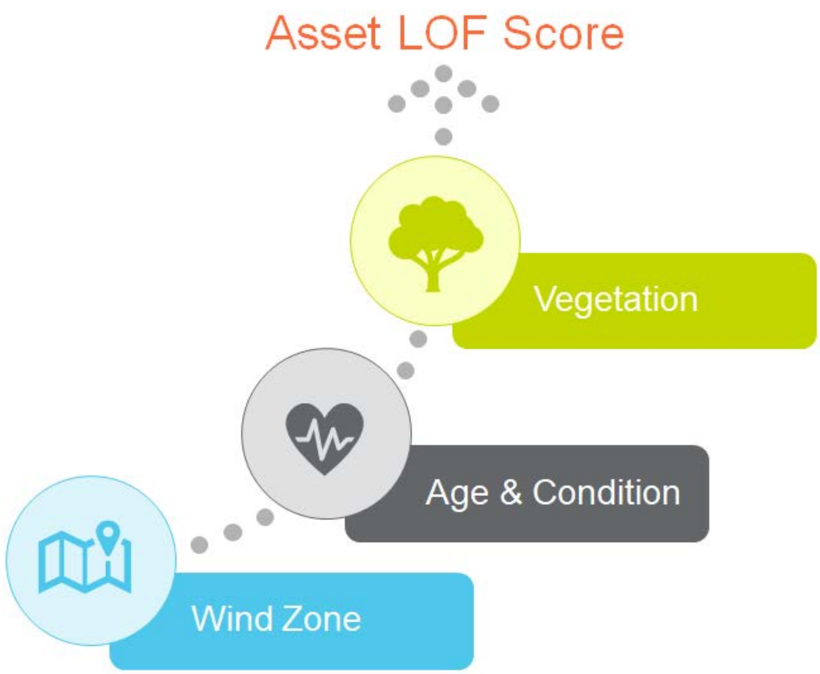
### 4.2.2 Circuits Storm Likelihood of Failure

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, 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.

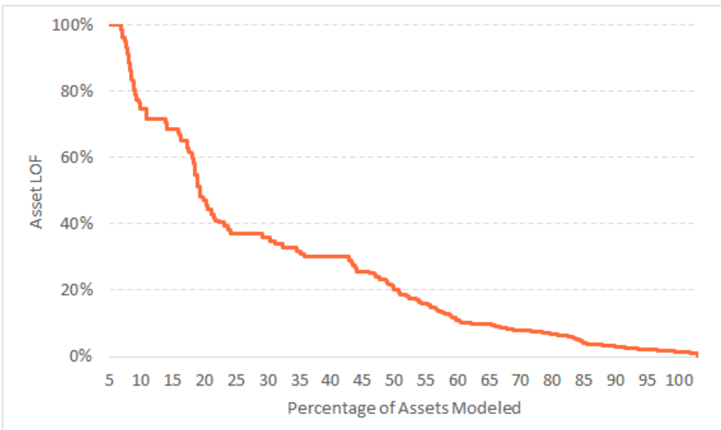
**Figure 4-5: Storm LOF Framework for Circuit Assets**




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

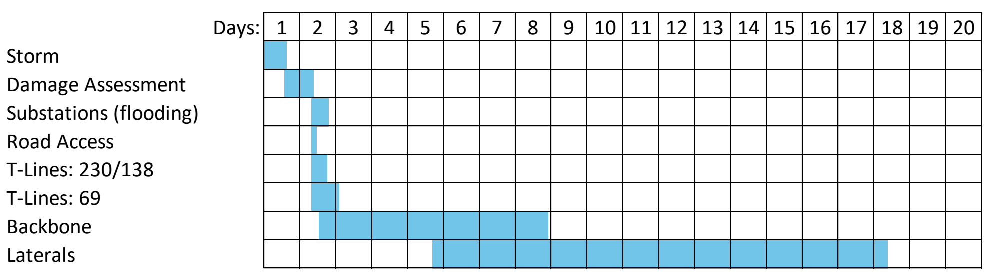
The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, 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 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.

### 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 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 |

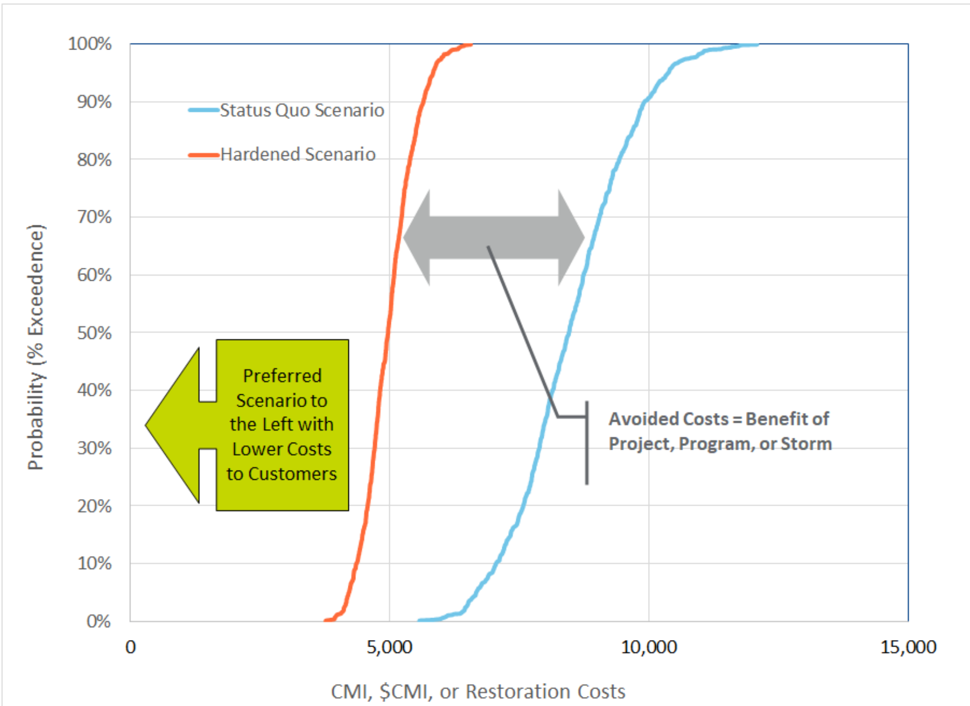
Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the 'Status Quo' and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and 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

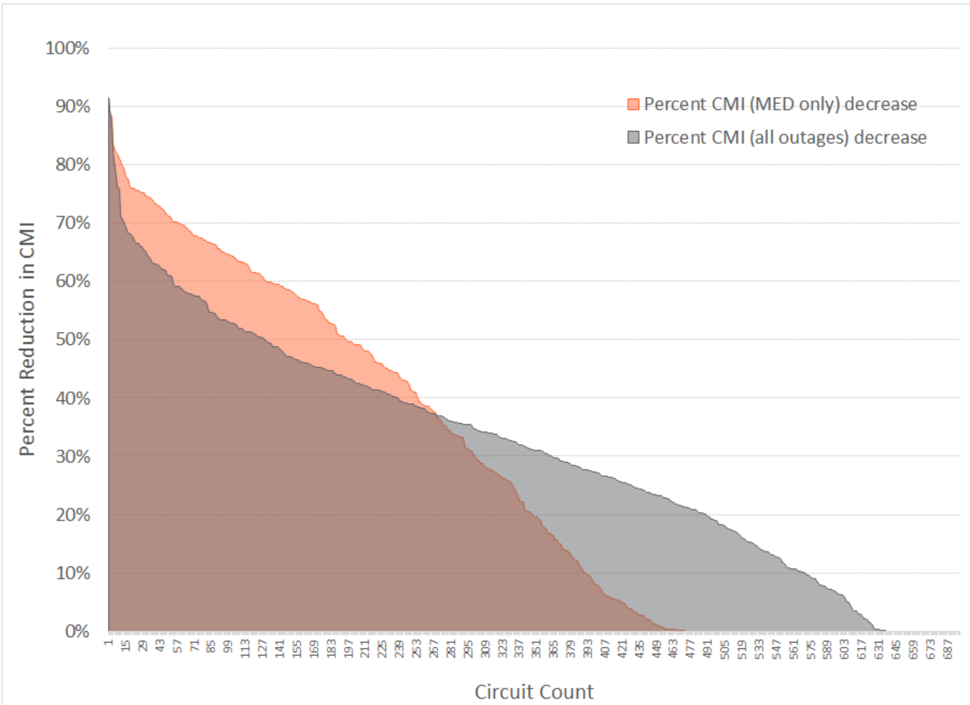
OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED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

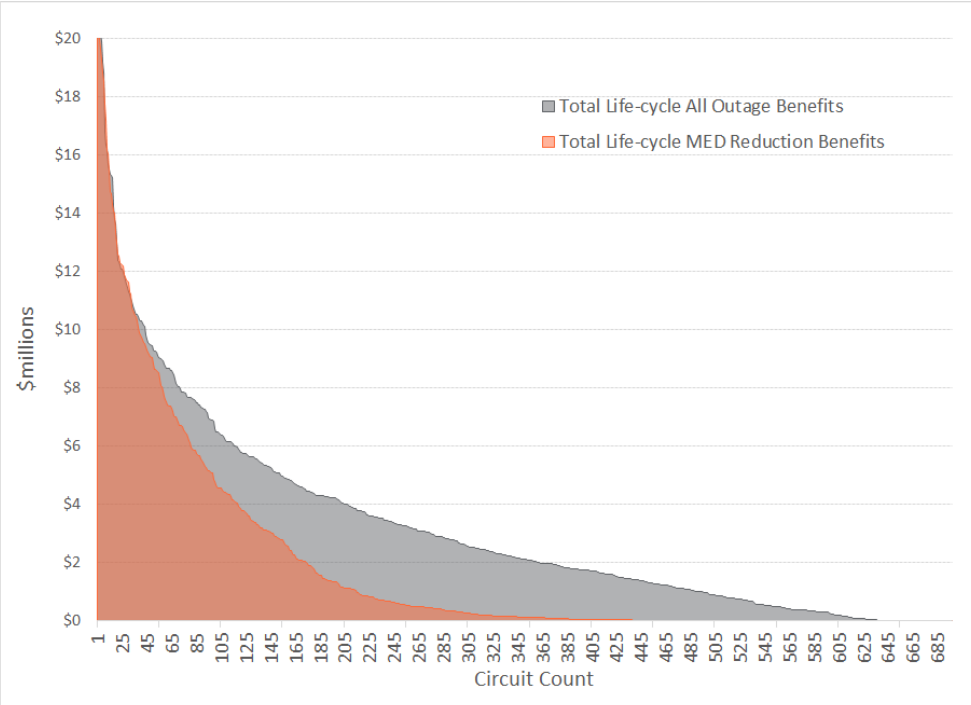
Figure 5-2 shows the percent decrease in CMI using this approach for all circuits. The figure is ranked from highest to lowest from left to right. The figure also includes the benefits to all outages. The figure shows a wide range of decreased CMI percentages with nearly 40 percent of circuits resulting 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**



# 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

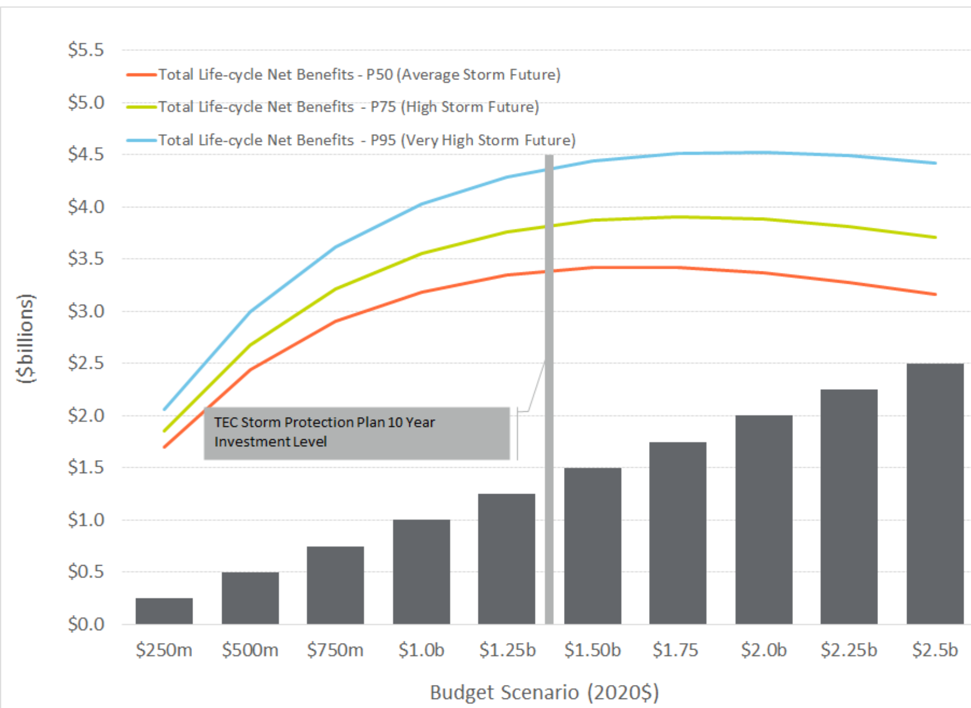
With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50 year NPV gross benefit value listed above. The ranking is performed for each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

# 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.

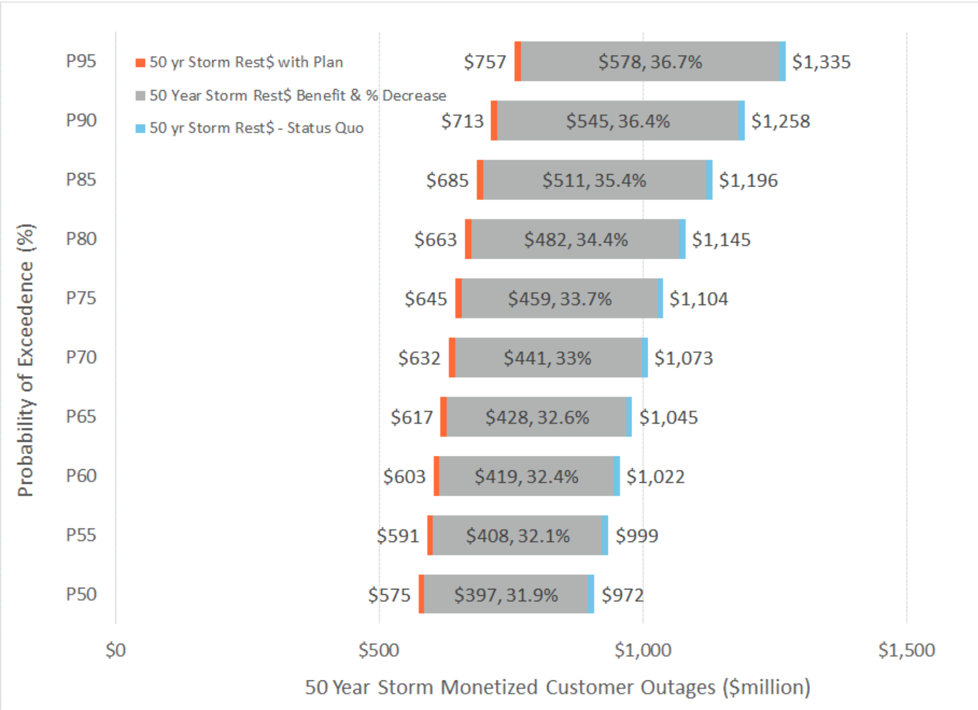
**Table 7-1: Storm Protection Plan Investment Profile by Program (Nominal $000)**

| 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**

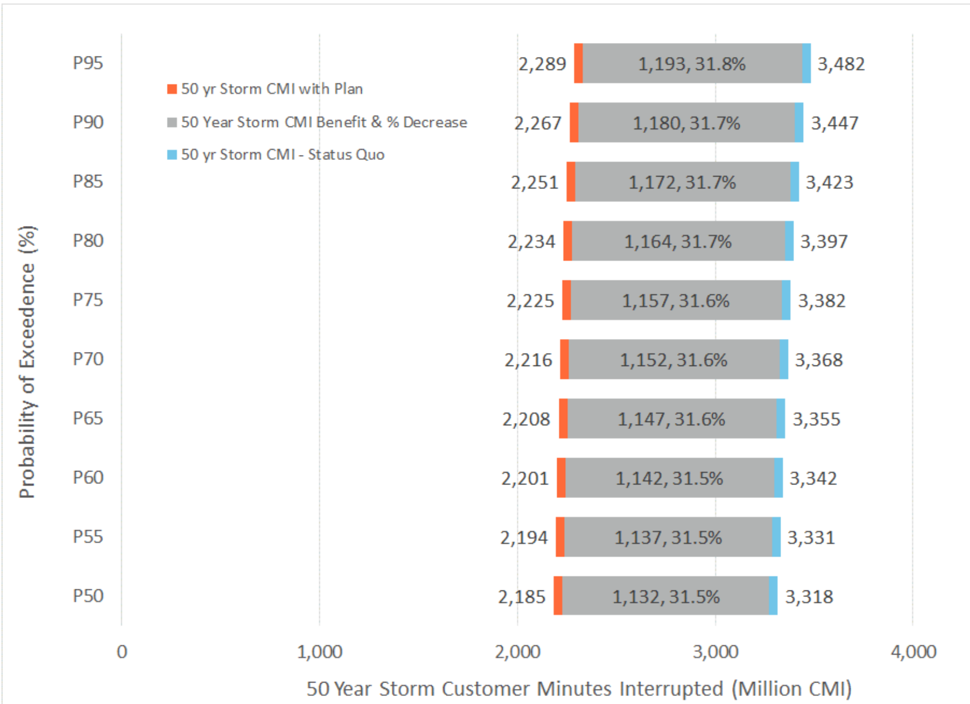



The figure shows that the 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to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

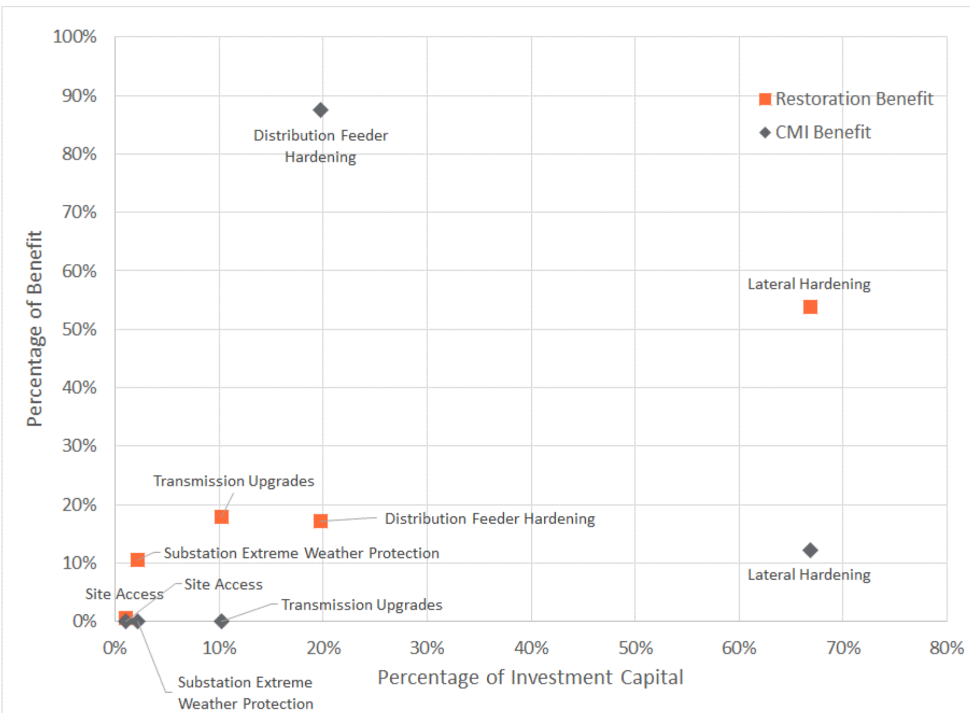



Table 7-7 and Figure 7-3 shows

- 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.

- 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.

- 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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# Appendix G

# Accenture, Tampa Electric's Vegetation Management Storm Protection Program Analytic Support Report

# VEGETATION MANAGEMENT STORM PROTECTION PROGRAM ANALYTIC SUPPORT REPORT

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## 1 Executive Summary

In 2019, the Florida Legislature enacted a law stating that each investor-owned electric utility (utility) must file a Transmission and Distribution Storm Protection Plan (SPP) with the Florida Public Service Commission ("FPSC").[1] The SPP must cover the utility's immediate ten-year planning period. Each utility must file, for Commission approval, an updated Storm Protection Plan at least every three years.[2] The SPP must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability.[3] The FPSC later promulgated a rule to implement the SPP filing requirement.[4] This rule went into effect in February of 2020.

Since damage from wind-blown vegetation is a major cause of outages during extreme weather conditions, the rule requires utilities to provide, for each of the first three years of the SPP, a description of its proposed vegetation management activities including:

A. The projected frequency (trim cycle);
B. The projected miles of affected transmission and distribution overhead facilities;
C. The estimated annual labor and equipment costs for both utility and contractor personnel; and
D. A description of how the vegetation management activity will reduce outage times and restoration costs in extreme weather conditions.[5]

TECO is proposing a VM Storm Protection Program that includes three distribution vegetation management initiatives:[6]

1. Four-year distribution vegetation management cycle
2. Incremental initiative to augment annual distribution trimming by targeting supplemental miles each year:
    a. 400 miles in 2020
    b. 500 miles in 2021
    c. 700 miles in 2022 and beyond
3. Consolidate the gains of the baseline distribution cycle trim and supplemental trimming by introducing mid-cycle distribution vegetation inspections two years beyond each trim to prescribe additional distribution VM activities to:
    a. Ensure fast-growing species are kept in check until the next scheduled trimming.
    b. Remove troublesome species, hazard trees, and/or trees putting sensitive infrastructure at risk.

    The mid-cycle initiative will be phased in with the inspections applied to the feeder portion of circuits starting in 2021, rolling out to full circuits (feeder and lateral) starting in 2023.

Beyond the day-to-day and storm benefits, the distribution portion of the VM Storm Protection Program is planned to scale up over time, moving from today's complement of 196 field resources to a peak of 280 field resources across three years, and then settling into a steady-state number of approximately

[1] § 366.96(3), Fla. Stat.
[2] Document No 09233-2019 Filed on 10/7/2019 with the FPSC, 25-6.030 Storm Protection Plan, p. 1, lines 2-6
[3] § 366.96(3), Fla. Stat. 1
[44] *See* R. 25-6.030, F.A.C.
[5] Document No 09233-2019 Filed on 10/7/2019 with the FPSC, 25-6.030 Storm Protection Plan, p. 3, lines 10-17
[6] The Vegetation Management Program also includes the baseline transmission trim cycles as well an incremental transmission vegetation management initiative, but those activities are outside of the scope of this report.

270 field resources. The phased rollout and associated resource load and budget are outlined in Table 1-1, below:

**Table 1-1: Recommended Approach**

| | Baseline 4-Year Cycle | Supplemental Miles | Feeder Mid-Cycle | Lateral Mid-Cycle | Estimated Resource Load[7] | Budget[8] |
|---|---|---|---|---|---|---|
| **2020** | Yes | 400 | Pilot 1-5 Circuits | None | 228 | $17.1M |
| **2021** | Yes | 500 | Inspect 60 Miles | None | 257 | $20.0M |
| **2022** | Yes | 700 | Inspect 48 Miles | Pilot 1-5 Circuits | 262 | $21.4M |
| **2023** | Yes | 700 | Inspect 46 Miles | Inspect 208 Miles | 280 | $24.0M |
| **2024** | Yes | 700 | Inspect 45 Miles | Inspect 177 Miles | 270 | $24.3M |
| **2025** | Yes | 700 | Inspect 96 Miles | Inspect 156 Miles | 270 | $25.5M |
| **2026** | Yes | 700 | Inspect 60 Miles | Inspect 150 Miles | 270 | $26.8M |
| **2027** | Yes | 700 | Inspect 45 Miles | Inspect 198 Miles | 270 | $28.1M |
| **2028** | Yes | 700 | Inspect 52 Miles | Inspect 155 Miles | 270 | $29.5M |
| **2029** | Yes | 700 | Inspect 54 Miles | Inspect 186 Miles | 270 | $31.0M |

These initiatives are projected to reduce day-to-day vegetation-caused customer interruptions by 21 percent and storm-related vegetation-caused outages by 29 percent relative to carrying out the 4-Year Trimming Cycle alone.

[7] Resource projections from 2023 forward fluctuate with the specific blend of circuits that come up for mid-cycle trimming each year. 270 represents the average for these years, and TECO will manage the mid-cycle scope to match budget.
[8] Budget reflects anticipated vegetation management costs for 1) the baseline 4-year cycle trim, 2) supplemental trim miles, 3) mid-cycle activities and 4) corrective maintenance. Excluded are the anticipated company-wide restoration costs associated with day-to-day outages and major storm events

## 2 Overview

TECO engages in 4-year distribution cycle trimming activities on an ongoing basis, working approximately one quarter of their overhead distribution system mileage every year. The goal is to trim tree limbs such that it will take four years before they can grow sufficiently to encroach on the clearances established for their lines. At various locations in the system, certain fast-growing tree species and/or right-of-way constraints on trimming result in isolated patches that may require attention between scheduled cycle trims. This often takes the form of Corrective Maintenance, where a crew is called out to address an impending issue on a specific tree because its limbs have grown too close to the line or because a tree, aided by the elements, makes contact with the lines and triggers an outage.

TECO continuously analyzes its vegetation management program using some of the industry's leading analytic tools. One of these tools is the Tree Trimming Model (TTM), originally developed by Davies Consulting (acquired by Accenture in 2017). Since the initial implementation of the model in 2006, TECO has continued to refine its program and update the tool's configuration using its growing set of historical spending and reliability performance data.

The TTM employs an analysis of day-to-day outages caused by vegetation, as well as a sampling of outages with unknown and weather cause codes which might be attributable to vegetation. TTM considers such outages in the context of the amount of time that has elapsed since the last time the trees on that circuit were trimmed. Universally, the analysis shows that outage volumes rise as a function of time since last trim, but the degree to which outages and their reliability impact escalate vary as a result of factors such as tree density, tree species, voltage, customer density, microclimate and a variety of others. In the configuration stages of the TTM modeling, circuits are grouped according to their similarity in terms of outage escalation and grouped separately as a function of how expensive it is to trim them, yielding a matrix of combinations of reliability and cost groupings. These expressions of cost and reliability, as a function of time, drive a ten-year prioritization aimed at getting the best day-to-day performance per dollar spent on trimming activities.

During extreme weather conditions, the proximity of limbs to lines and the cross-sectional area of vegetation upon which winds can exert force (referred to herein as the 'sail area') play a large factor in the degree of damage the electrical system will sustain due to vegetation-caused outages. Because the time elapsed since last trim is a direct driver of vegetation to conductor clearances when a storm arrives, the relationship between years since last trim, wind speed, and the extent of damage sustained has been studied and built into TTM's Storm Module. Using the trim list outputs of the TTM and an array of probable windspeeds for the Tampa area, the Storm Module predicts damage levels and associated restoration costs for typical years and can also project the impact of storms of specified magnitude.

Both TTM and the Storm Module address the effects of trimming circuits in their entirety, but some of TECO's proposed Vegetation Management initiatives are more targeted and address only portions of circuits in any given year. To accommodate this, Accenture crafted an Enhanced Storm Module for TTM to estimate the value derived from these targeted initiatives which change the state of only part of any given circuit at a time.

## 3 Approach

TECO used TTM and its storm modules to establish a set of baseline performance metrics associated with its four-year cycle, and then evaluated supplemental activities against that baseline:

- Supplemental trimming scenarios in which TECO targeted and trimmed an additional 100, 300, 500, 700 or 900 miles per year, and
- Mid-cycle activities whereupon circuits (either the feeder or the complete circuit) are inspected two years after their most recent trim, and follow-up vegetation management activities are prescribed to enhance both the day-to-day and extreme weather condition performance of the system.

The effects of the supplemental trimming and mid-cycle initiatives build upon the base of the 4-year trimming cycle. For consistency of presentation throughout the document, all three are referred to herein as initiatives:

**Table 3-1: Initiative Approach**

| Initiative | Name |
|---|---|
| 1 | Baseline 4-year Trimming Cycle |
| 2 | Supplemental Trimming |
| 3 | Mid-cycle Inspection & VM Activities |

The effects of these initiatives are cumulative, in that any version of Initiative 2 requires that the baseline 4-year cycle to be in effect, and Initiative 3 would not be implemented without the baseline trim cycle and Initiative 2 in place. There are many different combinations of activities, any of which could serve as the company's VM program. The benefits of each possible activity can only be evaluated by comparing the benefits of different programs, or combinations of activities. Consequently, the team created different possible VM programs, each with a different set of component activities. The programs which appear in this document consist of component activities as follows:

**Table 3-2: Program Nomenclature and Initiative Components**

| Program Name | Initiative 1 Component | Initiative 2 Component | Initiative 3 Component |
|---|---|---|---|
| **Program 1** | 4-year cycle trim | n/a | n/a |
| **Program 2 – 100** | 4-year cycle trim | 100 Supplemental Miles | n/a |
| **Program 2 – 300** | 4-year cycle trim | 300 Supplemental Miles | n/a |
| **Program 2 – 500** | 4-year cycle trim | 500 Supplemental Miles | n/a |
| **Program 2 – 700** | 4-year cycle trim | 700 Supplemental Miles | n/a |
| **Program 2 – 900** | 4-year cycle trim | 900 Supplemental Miles | n/a |
| **Program 3a – 700** | 4-year cycle trim | 700 Supplemental Miles | Mid-cycle on feeders only |
| **Program 3b – 700** | 4-year cycle trim | 700 Supplemental Miles | Mid-cycle on whole circuits |
| **Program 2 – 457** | 4-year cycle trim | Phased approach – 400 Supplemental Miles in 2020, 500 in 2021 and 700 in 2022 and beyond | n/a |
| **Program 3ab - 457** | 4-year cycle trim | Phased approach – 400 Supplemental Miles in 2020, 500 in 2021 and 700 in 2022 and beyond | Phased approach – mid-cycle on feeders only in 2021 and 2022, mid-cycle on full circuits in 2023 and beyond |

Upon finding an optimal endpoint, TECO examined the resource implications of the program and adapted the approach to phase in both the supplemental trimming initiative and the mid-cycle initiative to allow for a smooth transition into the program.

Prior to running the various scenarios, TECO engaged Accenture to refresh the TTM configuration and the various assumptions built into the TTM Storm Module. The configuration process and associated assumptions are captured in Section 6: Tree Trimming Model & Modules Configuration.

## 4 Storm Protection Initiatives Analysis

TECO and Accenture analyzed several vegetation management activities to determine an optimal level of supplemental trimming to reduce vegetation related outages during extreme weather events while continuing to minimize day-to-day vegetation related outages.

The following initiatives were considered:

**Table 4-1: Vegetation Management Initiatives Analyzed**

| | Initiative Name | Initiative Description | Modeling Methodology |
|---|---|---|---|
| **1** | Baseline: 4-Year Effective Cycle | Trim 25% of TECO's overhead lines (~1,562 miles) annually. | Target 25% of the miles in each of TECO's 7 districts for trimming annually. |
| **2** | Supplemental Circuit Trimming | Trim an additional 100 – 900 targeted miles annually with a view to mitigating outage risk on those circuits most susceptible to storm damage | Five scenarios modeled – 100, 300, 500, 700 and 900 miles. Due to the nature of the algorithm and available targeting data, targeting is based on SAIFI performance in regular weather. |
| **3a** | Mid-cycle VM Initiative – Feeders Only | Add mid-cycle inspections to feeder portions of circuits (~35% of line miles) two years after trim, prescribing additional VM activities to a fraction of the trees inspected. | The TTM Enhanced Storm Module assumes that one quarter of the trees inspected will be targeted for re-trimming when inspected and promptly trimmed. As TTM works with miles of circuit rather than individual trees, this is modeled as one quarter of the feeder miles re-setting to trimmed in that year, while the remainder of the circuit continues to age. Within the model, the costs associated with day-to-day restoration, storm restoration, and corrective maintenance costs are re-calculated to reflect the new trim-age profile of the circuit. |
| **3b** | Mid-cycle VM Initiative – Full Circuits | Extend the inspection and prescribed activities described in Initiative 3a to the entire circuit. As with 3a, it is assumed that a fraction of the trees inspected will require mid-cycle VM activities. | As described above in Initiative 3a, TTM Enhanced Storm Module assumes one quarter of the entire circuit is re-trimmed at two years, with an impact on day-to-day restoration costs, storm restoration costs and corrective maintenance costs. |

The Supplemental Circuit Trimming initiative seeks to reduce tree-caused outages by reducing the proximity between tree limbs and lines, as well as reducing trees' sail area which would otherwise cause them to sway or break as wind speed increases.

The Mid-cycle VM initiative focuses on some of the same proximity and sail area reduction efforts on the trees which grow the quickest and may encroach on lines despite the best efforts of the trimming cycle and supplemental trimming, as well as other activities to slow tree growth or eliminate hazard trees altogether.

## 4.1 Baseline Trim Cycle and Initiative 1 Variants

TECO and Accenture ran the company's ongoing 4-year cycle trim through the model to project its full budget implications across seven categories of cost to form a baseline against which the incremental benefits of supplemental trimming activities can be measured. The associated costs are broken out as follows, along with indicators as to whether the cost component in question is part of the VM budget and whether the costs are associated uniquely with VM resources or, as in the case of outage restorations, extend further into the organization:

**Table 4-2: Cost Categories**

| Cost Category | Applies to what resources? | Part of Storm Protection Program | Part of VM Budget? |
|---|---|---|---|
| **Cycle Trimming** | Vegetation | Yes | Yes |
| **Supplemental Trimming** | Vegetation | Yes | Yes |
| **Mid-Cycle** | Vegetation | Yes | Yes |
| **Corrective Cost** | Vegetation | No | Yes |
| **Resource Premiums** | Vegetation | Yes | Yes |
| **Day to Day Restoration Costs** | Line & Vegetation | No | No |
| **Storm Restoration Costs** | Line & Vegetation | No | No |

Note that the anticipated spending levels for the two categories of restoration cost are driven by vegetation management decisions but are not part of the vegetation management budget. They are considered and presented within this analysis because the investments in enhancing vegetation management for the Storm Protection Plan should be offset by reductions in cost due to outage response.

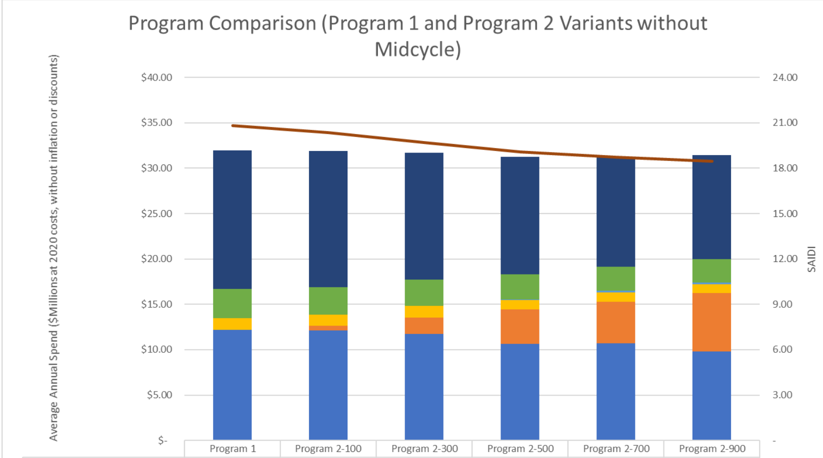
In the baseline scenario, each service area is allotted one quarter of its mileage every year, or approximately 1,562 miles in total. Central, for example, accounts for one sixth of TECO's overhead miles, and is afforded one sixth of the annual 1,562-mile budget as depicted below.

**Table 4-3: Baseline 4-Year Effective Cycle Mileage Targets**

| Service Area | Mileage Target | Percentage |
|---|---|---|
| **Central** | 260 | 16.6% |
| **Dade City** | 93 | 6.0% |
| **Eastern** | 209 | 13.4% |
| **Plant City** | 310 | 19.8% |
| **South Hillsborough** | 182 | 11.7% |
| **Western** | 277 | 17.7% |
| **Winter Haven** | 231 | 14.8% |
| **Total** | 1,562 | 100.0% |

In the supplemental trimming initiatives, one quarter of the supplemental miles is allocated across the service areas in the same proportions as the 4-year distribution trim cycle. The remainder of the miles are directed where they will deliver the greatest benefit. Thus, in a scenario where 400 supplemental miles were trimmed, 100 miles would be constrained with 16.6 occurring in Central, 6.0 miles in Dade City, 13.4 miles in Eastern, and so on with the remaining 300 miles of trimming directed to the areas where it would deliver the greatest benefit.

The costs for the baseline scenario and five variants of supplemental trimming, without mid-cycle, are plotted below:




| | Program 1 | Program 2-100 | Program 2-300 | Program 2-500 | Program 2-700 | Program 2-900 |
|---|---|---|---|---|---|---|
| Storm Restoration Cost | $15.31 | $14.99 | $13.97 | $12.92 | $12.08 | $11.42 |
| Day-to-Day Restoration Cost | $3.19 | $3.05 | $2.91 | $2.77 | $2.69 | $2.63 |
| Resource Premiums | $- | $0.03 | $0.00 | $0.05 | $0.14 | $0.15 |
| Corrective Cost | $1.30 | $1.23 | $1.30 | $1.08 | $1.03 | $0.99 |
| Mid-Cycle Cost | $- | $- | $- | $- | $- | $- |
| Supplemental Trimming Cost | $- | $0.50 | $1.80 | $3.81 | $4.62 | $6.44 |
| Baseline 4-Year Cycle Cost | $12.19 | $12.10 | $11.72 | $10.61 | $10.69 | $9.79 |
| SAIDI | 20.83 | 20.36 | 19.70 | 19.09 | 18.75 | 18.45 |

**Figure 4-1: Program Comparison**

The average annual vegetation management budget, without inflation, for these six options ranges from $13.5M for the as-is 4-year trimming cycle to $17.4M for the cycle plus 900 miles of supplemental trimming annually. Meanwhile the annual total restoration costs, which include all line work and vegetation management costs for storm restoration, trend in the opposite direction from $18.5M for the baseline 4-year cycle to $14.1M for the 900-mile variant. The total anticipated cost of the VM budget and restoration combined sits in a narrower range, at $32.0M for the baseline 4-year cycle and $31.25 M for the 500 and 700-mile variants.

The side-by-side comparison of scenarios yields several insights:

- The introduction of supplemental trimming drives down the cost of the baseline four-year cycle. This is because the extra activity on the lines makes trimming the annual 1,562 miles less expensive each year since the tree limbs have had less time to grow and are neither as long nor as close to the lines as they would have been otherwise.
- The increases in cost associated with the Storm Protection Program 2 variants and associated resource premiums is offset by decreases in cost in the 4-year cycle trim, corrective maintenance, day-to-day restoration costs and storm restoration costs, up to the 500 to 700-mile range.
- Although difficult to see in Figure 4-1, the 500 mile and 700-mile programs yield the best overall average annual cost, which, due to diminishing returns, begins to trend back upwards starting with the 900-mile program. See Figure 4-2, below, for a view focused on total cost.
- Each supplemental increase in Program 2 yields an improvement in SAIFI and SAIDI, although the gains slow in the 500-mile to 700-mile range.

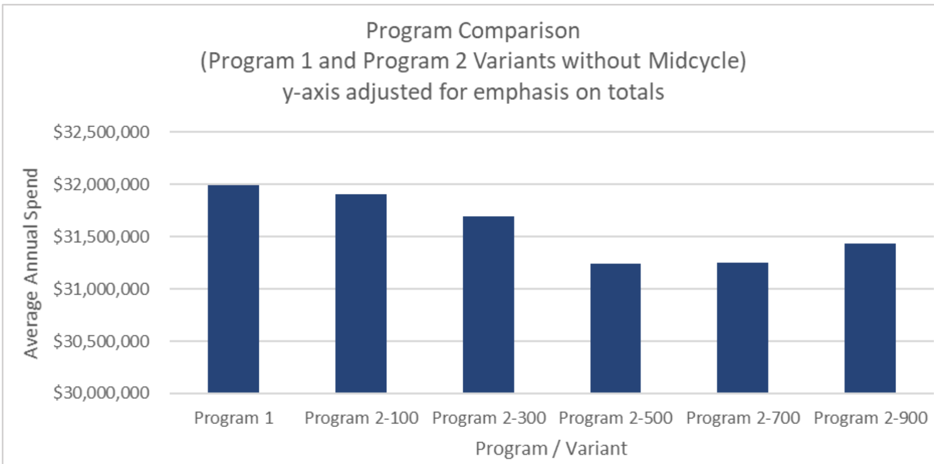



**Figure 4-2: Program Comparison with Focus on Total Average Annual Spend**

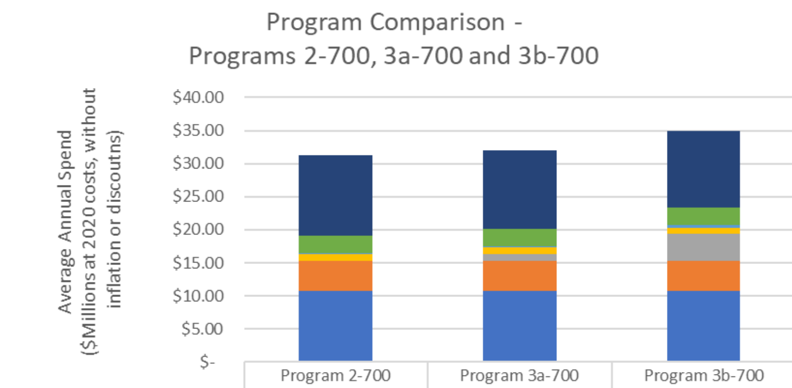
- While the 500 mile and 700-mile programs are in a virtual tie from an overall cost perspective, there is a clear advantage to the 700-mile program from the customer experience perspective. The 700-mile program drives 16 percent and 21 percent improvements in the ten-year average day-to-day and storm restoration costs, which are directly linked to customer interruptions. Across the ten-year span of the 500-mile program, these figures are 13 percent and 16 percent.

**Table 4-4: 10-year Average Outage Restoration Improvements for Programs 2-500 and 2-700 Relative to Program 1**

| Cost Element | Program 1 Average 2020-2029 | Program 2-500 Average 2020-2029 | Program 2-700 Average 2020-2029 | Improvement for Program 2-500 | Improvement for Program 2-700 |
|---|---|---|---|---|---|
| **Day-to-Day Restoration** | $3.19 M | $2.77 M | $2.69M | 13.2% | 15.7% |
| **Storm Restoration** | $15.31 M | $12.92M | $12.08M | 15.6% | 21.1% |

## 4.2 Storm Protection Initiative 3a & 3b – Mid-cycle Inspection and VM Activities

Based on the results presented in Section 4.1, Initiatives 3a and 3b were analyzed in the context of Program 2-700, where 700 supplemental and targeted miles are trimmed each year. The average annual cost of the inspectors and VM resources for the mid-cycle initiatives was $1.06M and $4.05M, respectively, and they yielded a further 2.5 percent and 4.5 percent improvements to storm restoration costs from $12.08M to $11.77M and $11.54M.




| | Program 2-700 | Program 3a-700 | Program 3b-700 |
|---|---|---|---|
| Storm Restoration Cost | $12.08 | $11.77 | $11.54 |
| Day-to-Day Restoration Cost | $2.69 | $2.68 | $2.65 |
| Resource Premiums | $0.14 | $0.16 | $0.45 |
| Corrective Cost | $1.03 | $0.99 | $0.95 |
| Mid-Cycle Cost | | $1.06 | $4.05 |
| Supplemental Trimming Cost | $4.62 | $4.62 | $4.62 |
| Baseline 4-Year Cycle Cost | $10.69 | $10.69 | $10.69 |

**Figure 4-3: Storm Protection Program Mid-Cycle Comparison**

**Table 4-5: 10-year Average Outage Restoration Improvements for Programs 3a-700 and 3b-700 Relative to Program 2-700**

| Cost Element | Program 2-700 Average 2020-2029 | Program 3a-700 Average 2020-2029 | Program 3b-700 Average 2020-2029 | Improvement for Program 3a-700 | Improvement for Program 3b-700 |
|---|---|---|---|---|---|
| **Storm Restoration** | $12.08M | $11.77M | $11.54M | 2.6% | 4.5% |
| **Day-to-Day Restoration** | $2.69M | $2.68M | $2.65M | 0.4% | 1.5% |

As noted previously, the modeling approach may not reflect the full value of the mid-cycle activities. While the Tree Trimming Model considers circuits in their entirety, the mid-cycle initiative would be targeted based on inspections and storm impact and is highly likely to yield greater benefits than what is reflected here. Also, some of the prescribed activities under the mid-cycle initiative, such as tree removals, will yield permanent and cumulative results not captured here. Simply put, it is believed that the benefits of the mid-cycle initiative will exceed what is shown here.

## 4.3 Developing a Blended Strategy to Accommodate Resource Constraint

Resource impact is one final element to draw out of the Storm Protection Program 2 and Storm Protection Program 3a/3b analyses. The 500, 700, and 900-mile versions of Storm Protection Program 2 all incur cost premiums associated with the rapid increase in size to the workforce required. Programs

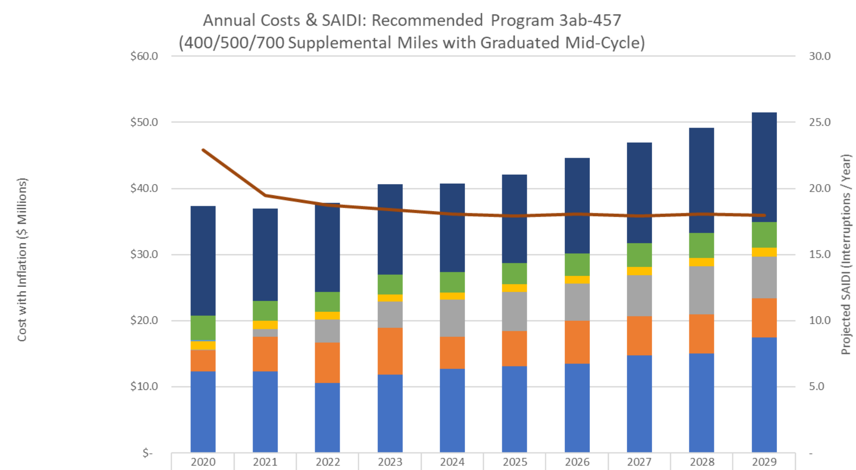
3a-700 and 3b-700 exacerbate the resource crunch. While the average annual VM budget (without inflation) for Program 2-700 (Baseline + 700 supplemental miles) is estimated at $16.4M and would require an average of 220 resources to execute, the first year VM budget would be $19.0M and require roughly 256 resources. With 196 resources in the field at present, the uptake of 60 workers in a single year would represent a very large challenge and require significant expenditure on overtime and premium incentives to achieve, particularly if the transition happens later in the year. Adding Initiative 3a or 3b simultaneously would further exacerbate the issue.

TECO is proposing instead to transition towards the 700-mile version of Initiative 2 over the course of three years by trimming 400 extra miles in 2020, 500 extra miles in 2021 and finally arriving at the 700-mile program in 2022. The mid-cycle initiative will also be introduced gradually, addressing feeders alone in the second and third years and moving towards inspecting full circuits in the fourth year and beyond as better data becomes available about the success of mid-cycle inspections and VM activities.

## 5 Recommendation

The recommended Vegetation Management Storm Protection Program (Program 3ab-457) consists of the following activities:

1) **Baseline Cycle**: continue the 4-year trimming cycle
2) **Supplemental trimming initiative**: scale up supplemental trimming miles by targeting an additional 400 miles in 2020, 500 miles in 2021, and 700 miles from 2022 going forward
3) **Mid-cycle VM initiative**: introduce mid-cycle inspections and associated targeted activities for the feeder portions of circuits in 2021, extending the inspections and prescribed activities to cover entire circuits from 2023 forward, with 60 miles inspected in 2021, 48 miles in 2022 and 254 miles in 2023 as the program rolls out to entire circuits.




| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Storm Restoration Cost | $16.6 | $13.9 | $13.5 | $13.6 | $13.3 | $13.4 | $14.4 | $15.3 | $16.0 | $16.6 |
| Day-to-Day Restoration Cost | $3.6 | $3.0 | $2.9 | $3.0 | $3.1 | $3.2 | $3.4 | $3.5 | $3.7 | $3.9 |
| Resource Premiums | $0.2 | $- | $- | $- | $- | $- | $- | $- | $- | $- |
| Corrective Cost | $1.3 | $1.3 | $1.2 | $1.1 | $1.1 | $1.1 | $1.2 | $1.2 | $1.3 | $1.3 |
| Mid-Cycle Cost | $0.1 | $1.2 | $3.5 | $4.0 | $5.6 | $6.0 | $5.7 | $6.2 | $7.3 | $6.3 |
| Supplemental Trimming Cost | $3.2 | $5.2 | $6.1 | $7.1 | $4.8 | $5.3 | $6.5 | $5.9 | $5.9 | $5.9 |
| Baseline 4-Year Cycle Cost | $12.4 | $12.3 | $10.5 | $11.8 | $12.7 | $13.1 | $13.4 | $14.7 | $15.0 | $17.5 |
| SAIDI | 22.9 | 19.5 | 18.8 | 18.4 | 18.1 | 17.9 | 18.1 | 17.9 | 18.1 | 18.0 |
| Estimated Resource Requirement | 228 | 257 | 262 | 280 | 270 | 270 | 270 | 270 | 270 | 270 |

**Figure 5-1: Annual Costs and SAIDI – Recommended VM Program**

The VM Budget (SPP and Non-SPP) and Restoration Costs are summarized below:

**Table 5-1: VM Storm Protection Program 3ab-457 Performance Characteristics**

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total VM Budget | $17.1 | $20.0 | $21.4 | $24.0 | $24.3 | $25.5 | $26.8 | $28.1 | $29.5 | $31.0 |
| Restoration Costs | $20.3 | $17.0 | $16.5 | $16.6 | $16.4 | $16.6 | $17.8 | $18.8 | $19.7 | $20.5 |
| Total VM-Influenced Costs | **$37.4** | **$36.9** | **$37.9** | **$40.6** | **$40.7** | **$42.1** | **$44.6** | **$46.9** | **$49.2** | **$51.5** |

From a benefits perspective, two measures are worth exploring because the program takes a few years to establish: the overall ten-year average performance, and the future steady-state value taken in this case by considering the average of the last five years in the analysis. For the 10-year and 5-year end state averages, all years and cost elements are priced at 2020 rates, with no inflation.

**Table 5-2: VM Storm Protection Program 3ab-457 Performance Characteristics**

| | 10-Year Average | | | Future Steady-State (Average of Last Five Years) | | |
|---|---|---|---|---|---|---|
| | Program 1 | Program 2-457 | Program 3ab-457 | Program 1 | Program 2-457 | Program 3ab-457 |
| **SAIFI** | 0.229 | 0.195 | 0.193 | 0.227 | 0.184 | 0.181 |
| **SAIDI** | 20.8 | 18.9 | 18.8 | 20.7 | 18.2 | 18.0 |
| **Typical Storm Season** | $15.3 M | $12.4 M | $11.9M | $15.1 M | $11.4 M | $10.7 M |
| **65 mph Storm** | $16.6 M | $14.0 M | $13.3 M | $16.3 M | $13.2 M | $12.4 M |
| **85 mph Storm** | $37.1 M | $31.3 M | $29.8 M | $36.5 M | $29.6 M | $27.6 M |
| **105 mph Storm** | $69.9 M | $59.0 M | $56.1 M | $68.7 M | $55.7 M | $52.1 M |
| **125 mph Storm** | $117.9 M | $99.5 M | $94.6M | $109.8 M | $94.0 M | $87.9 M |

The proposed Program 3ab-457 is projected to improve SAIFI by 15.3 percent relative to the baseline 4-year cycle over the full period, or by 21.3 percent if just the final five years are considered. SAIDI improvement is 9.6 percent across ten years, or 14.0 percent in the future steady state. Storm performance improves by 22.2 percent across ten years, or 29.1 percent in the future steady state.

# 6 Tree Trimming Model & Modules Configuration

The Tree Trimming Model requires intermittent updates wherein the latest circuit configuration, trimming and outage history are employed to ensure the model is using the latest information available when targeting circuits for trimming. In addition, the storm module requires updates to a variety of cost and workforce assumptions to perform its functions correctly.

## 6.1 TTM Inputs and Assumptions

TTM requires three principal data sources:

- A complete inventory of the overhead circuits in the system, including circuit characteristics such as customer count, overhead mileage, and geographic coordinates;
- The outage database or databases; and,
- A history of trimming activity, preferably including start and end dates, costs, and covering multiple trims for each circuit.

### 6.1.1 Circuit List

A comprehensive list of circuits was obtained from TECO, which contained a total of 780 circuits.

Not all circuits and mileage were of interest, as TTM is only relevant to the overhead portion of circuits for which trimming is a regular concern. Ultimately, 709 “trimmable” circuits were included in the analysis, representing some 6,247 miles of overhead circuit length.

### 6.1.2 Performance Data

Circuit reliability performance data was gathered from TECO’s Distribution Outage Database (DOD). The analysis included outages from January 1, 2006 through November 26, 2019, thus accommodating at least thirteen years of data. Of interest were outages with the tree-related cause codes found in Table 6-1below. The table indicates the number of events associated with each cause code, as well as the total customer interruptions (CI) and customer minutes of interruption (CMI).

**Table 6-1: Tree-Related Cause Codes (January 1, 2006 - November 26, 2019)**

| Cause Code | Events | CI | CMI |
|---|---|---|---|
| **Tree\Blew into Line** | 305 | 20,060 | 1,219,189 |
| **Tree\Non-Prev.** | 9,970 | 811,842 | 68,744,420 |
| **Tree\ Prev.** | 9,776 | 740,361 | 66,143,332 |
| **Tree\Grew into Line** | 1,644 | 110,815 | 8,404,342 |
| **Tree\Vines** | 5,984 | 210,380 | 7,476,754 |
| **Trees (Other)** | 436 | 22,815 | 1,879,906 |
| **Incorporated Unknown** (25%) | 2,732 | 162,248 | 10,206,418 |
| **Incorporated Weather** (25%) | 6,190 | 389,703 | 35,775,171 |
| **Grand Total** | 37,037 | 2,468,224 | 199,849,532 |

TECO also incorporated a portion of CIs and CMIs from outages with "Unknown" and "Weather" cause codes. From experience, Accenture has found with other utilities that a significant portion of such catch-all causes is, in fact, tree-related. Therefore, after conducting an internal analysis of trends in outage counts for these cause codes in relation to explicit tree cause codes, TECO determined that 25 percent was a reasonable proportion to include in the analysis.

Finally, certain outages were excluded from this analysis irrespective of the cause code. These included those adjustments specified and allowed in accordance with Rule 25-6.0455, Florida Administrative Code.

### 6.1.3 Trim Data

TECO records and maintains trim history that includes the following types of data:

- Circuit number;
- Trim start date;
- Trim completion date;
- Miles trimmed; and,
- Cost to trim the entire circuit.

Similar to the performance data, the analysis included trimming data from January 1, 2006 through November 26, 2019. The trim data was pared down to the outage data with the circuit number being the link between the two data sources. For analysis purposes, the circuit number and trim completion date (year and month of trim) of each circuit trim were incorporated in the analysis.

## 6.2 Reliability Performance Curve Development

### 6.2.1 Creating Circuit Performance Groups

Circuits were ordered according to historical performance. A total of seven groups were identified so that around 1,130 miles were represented in each group. Group 07 were the circuits that had zero tree-related outages from 2006-2019.

**Table 6-2: CI Grouping Characteristics**

| Circuit CI Group | CI per Mile Criteria | Circuits | Miles |
|---|---|---|---|
| **01** | Greater than 649 | 164 | 1,117 |
| **02** | Between 467 and 649 | 95 | 1,135 |
| **03** | Between 277 and 467 | 131 | 1,136 |
| **04** | Between 193 and 277 | 70 | 1,134 |
| **05** | Between 104 and 193 | 101 | 1,132 |
| **06** | Between 0.3 and 104 | 168 | 1,130 |
| **07** | Less than 0.3 | 66 | 19 |

**Table 6-3: CMI Grouping Characteristics**

| Circuit CI Group | CMI per Mile Criteria | Circuits | Miles |
|---|---|---|---|
| **01** | Greater than 55,483 | 159 | 1,130 |
| **02** | Between 34,277 and 55,483 | 114 | 1,125 |
| **03** | Between 22,485 and 34,277 | 114 | 1,107 |
| **04** | Between 14,427 and 22,485 | 83 | 1,133 |
| **05** | Between 8,340 and 14,427 | 87 | 1,152 |
| **06** | Between 19.3 and 8,340 | 172 | 1,136 |
| **07** | Less than 19.3 | 66 | 19 |

### 6.2.2 Circuit Performance Curve Fitting

Performance data points were derived using historical outage data, trim data, and circuit length data. Every outage was expressed as a number of CI or CMI per circuit mile and was plotted relative to the most recent time it was trimmed. Values for 12 consecutive individual months were rolled up to create year-based values, and these were plotted in MS Excel so that a curve could be fit to them.

Several conditions had to be satisfied in order to ensure that the data points were correct:

- Outage data was omitted in the months when a circuit was being trimmed.

- Outages were associated only to the most recent trim.
- Figure 6-1 below reflects the mileage into which the 12-month roll-up of CI or CMI is divided and represents the total mileage of the system or group of circuits. This ensures that in a situation where several circuits do not have any outages in a particular 12-month roll-up, those circuits were not disregarded, but rather served to appropriately pull the curve downward as part of the averaging process. This provided assurance that the resulting curves were representative of the overall CI or CMI per mile of circuits in the group and not just the CI or CMI per mile on circuits that happened to have outages.

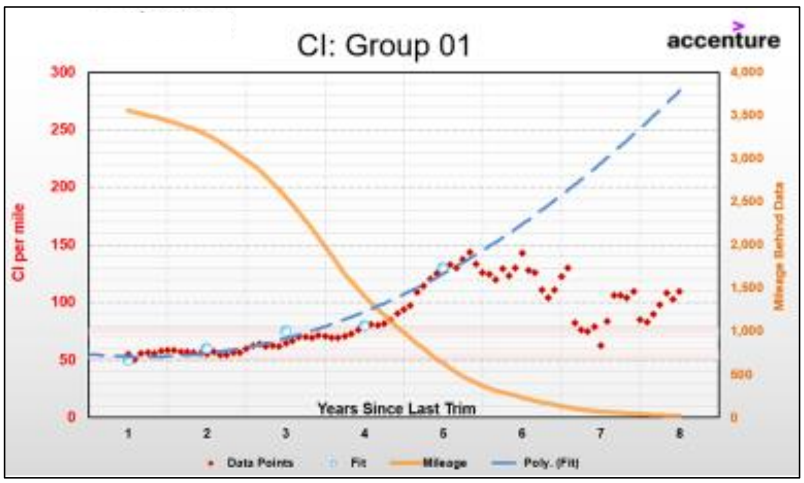



**Figure 6-1: Example of Curve Fitting Analysis**

A curve similar to that shown in Figure 6-1 was developed for each of the CMI groups, resulting in a total of fourteen curves, which are shown in Figure 6-2 and Figure 6-3 respectively. These curves provided the critical input required to compute the projected reliability associated with trimming each circuit. Eventually, the computed reliability values were used as the denominator to determine the cost-effectiveness score for circuits, which then served as the basis for their prioritization.

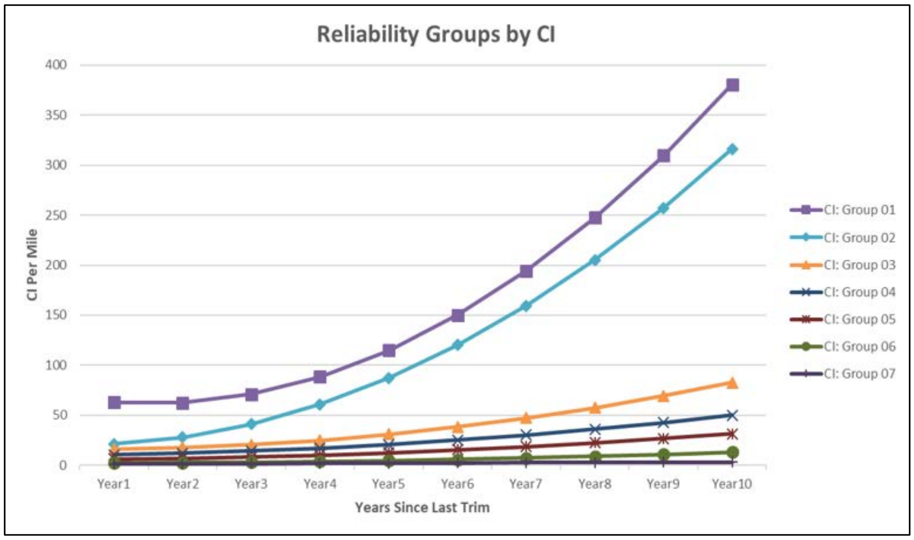



**Figure 6-2: Customer Interruption (CI) Curve Groups**

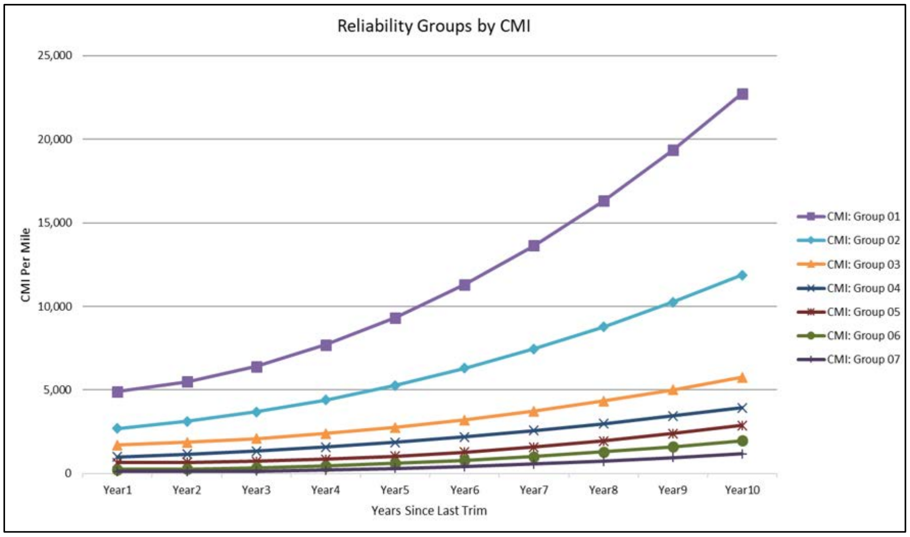



**Figure 6-3: Customer Minute Interruption (CMI) Curve Groups**

### 6.2.3 Cost Curves

Cost curves were the second factor in calculating the cost/benefit score of each circuit in TTM.

The shapes of the cost curves were based on a proprietary study called the Economic Impacts of Deferring Electric Utility Tree Maintenance by ECI[9] that quantified the percentage increase in the eventual cost of trimming a circuit for each year that it is left untrimmed beyond the recommended clearance cycle. The findings of the ECI study are summarized in Figure 6-4 below. For instance, if the clearance cycle is three years, then waiting four years between trims will increase the cost per mile by 20 percent. Delaying trimming by another year will further inflate costs to 40 percent of the base cost and further increase it for subsequent years.

The ECI study only considered annual trimming cost increases between the recommended clearance cycle and up to a four-year delay. In generating a comprehensive cost curve that goes from one year since last trim onward, Accenture supplemented the percentages from the ECI study with two assumptions:

- Cost reduction from annual trimming – the percentage reduction from the clearance trim that will be achieved if the circuit was trimmed every year; and,
- Escalation – annual percentage increase in cost to be applied from the ninth year and beyond.

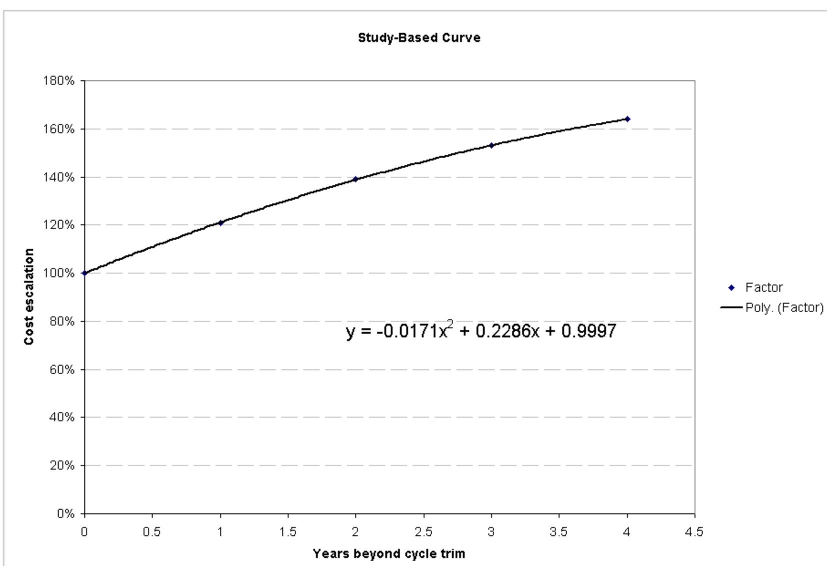



**Figure 6-4: ECI Study-Based Cost Curve**

The following section describes how such a cost curve methodology was applied to each cost group.

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[9] Browning, D. Mark, 2003, Deferred Tree Maintenance, Environmental Consultants Incorporated (ECI)

Similar to how the performance groups were created, circuits were ordered according to the average cost per mile. Initially a total of six groups were identified so that each had around 1,000 miles represented in each group. Group 01 ranged from $7,600/mile to $41,000/mile and it was important to further divide it into smaller groups due to the large range between costs. Ultimately, Group 01 was divided into 4 smaller groups so that the ranges were more reasonable. The same was true on the other side of the spectrum and the lowest cost group was split into two groups. Ultimately, circuits were grouped into 10 distinct groups as shown in the following table:

**Table 6-4: Cost Grouping Characteristics**

| Circuit Cost Group | Cost per Mile Criteria | Circuits | Miles |
|---|---|---|---|
| **01** | Greater than $25,000 | 14 | 79 |
| **02** | Between $15,500 and $25,000 | 26 | 158 |
| **03** | Between $10,000 and $15,500 | 42 | 225 |
| **04** | Between $7,600 and $10,000 | 90 | 713 |
| **05** | Between $6,100 and $7,600 | 103 | 1,088 |
| **06** | Between $5,000 and $6,100 | 109 | 1,016 |
| **07** | Between $4,100 and $5,000 | 91 | 1,037 |
| **08** | Between $3,300 and $4,100 | 89 | 1,058 |
| **09** | Between $1,500 and $3,300 | 116 | 896 |
| **10** | Less than $1,500 | 25 | 100 |

With this group information a curve was created for each using the average cost per mile in each group with an additional twenty-five percent increase on each. The additional twenty-five percent was added to adjust historical trimming costs to 2019 dollars. Since TECO is on a four-year effective trim cycle each cost group is anchored on Year 4 with its respective adjusted average cost per mile. The remaining points were determined using the expertise of TECO and Accenture:

- Years 1: A 35 percent reduction in average cost if TECO would return to a circuit a year later
- Years 2-3: Linear increase in spending from Year 1 to Year 4
- Years 5-8: Follow the cost escalation described in Figure 6-5.
- Years 9-10: A 5 percent increase for each year trimming is delayed

These datapoints and assumptions were used to fit a curve for each of the cost groups shown below:

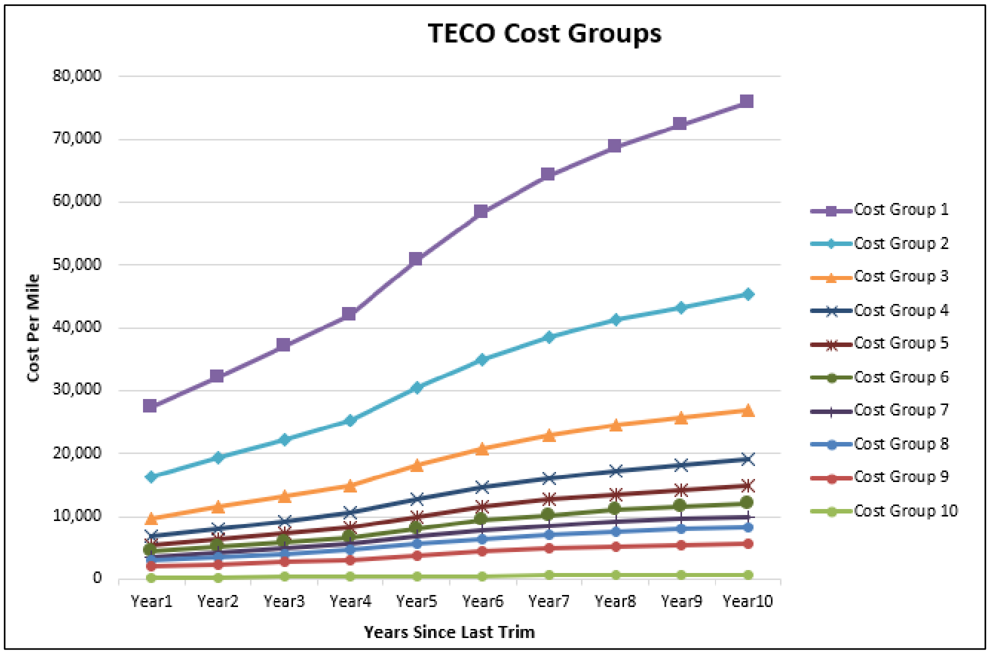


**Figure 6-5: Cost Groups**

TTM uses these curves to identify the estimated cost per mile to trim a circuit based on its year since last trim. These costs are in 2019 dollars and an estimated 5 percent inflation rate is used for subsequent trimming costs in future years.

## 6.3 Storm Module Inputs and Assumptions

Storm protection initiative cost and benefit modeling was accomplished using TTM and its associated Storm Module which have been used to prioritize trimming activities since 2006, and an Enhanced Storm Module to cover analyses not originally anticipated in the original Storm Module. The following cost implications were generated for each vegetation management activity considered:

**Table 6-5: Storm Module Cost Assumptions**

| Cost | Cost Generator | Key Assumptions |
|---|---|---|
| **Baseline: 4-Year Cycle Cost** | TTM Core Module | • Cost curves (TTM Configuration Analysis)<br>• Years since last trim (TECO records)<br>• Proportional allocation of mileage across work areas |
| **Supplemental Trimming Cost** | TTM Core Module | • Cost curves (TTM Configuration Analysis)<br>• Years since last trim (TECO records)<br>• Proportional allocation of mileage across work areas for 25% of supplemental miles |
| **Mid-Cycle VM Initiative Cost** | TTM Enhanced Storm Module | • Cost premium for inspection and enhanced activities (SME Estimate)<br>• Timing of mid-cycle activities (SME decision)<br>• Proportion of circuit population targeted (SME decision – 2 scenarios)<br>• Proportion of circuit targeted (SME decision) |
| **Corrective Maintenance Tickets** | TECO Subject Matter Expert Input | • Proportion of corrective maintenance tickets attributable to tree growth (TECO Records)<br>• Relationship between tree growth corrective maintenance tickets and system effective cycle (SME estimate, past filings) |
| **Premiums Associated with Attracting Additional Workforce** | TTM Core Module | • VM budget (Cycle + Supplemental + Mid-Cycle + Corrective)<br>• Straight and overtime loaded cost rates for VM crews (SME estimate)<br>• Maximum organic growth rate of the VM workforce (SME estimate)<br>• Productivity adjustment for training new VM resources (SME estimate)<br>• Incentive costs for VM resources required beyond the organic growth capacity (SME estimate) |
| **SAIDI-Driven Restoration Costs** | TTM Storm Module | • Reliability outputs from TTM Core Module<br>• Average cost to restore a CMI (SME estimate) |
| **Storm Restoration Costs** | TTM Storm Module | • Trim list from TTM Core Module<br>• Storm damage calculation function<br>• FEMA HAZUS windspeed return dataset |

| Cost | Cost Generator | Key Assumptions |
|---|---|---|
| | | • Average cost to restore in major event including mutual assistance (Irma Analysis, SME adjustment) |

### 6.3.1 Baseline: 4-Year Cycle Costs

Routine cycle trimming costs are projected by the Tree Trimming Model based on curves derived in the model configuration stages.

Cycle targets are established by declaring a number of miles to trim each year. In the baseline four-year scenario, the budget was allocated such that each service area would be on its own four-year cycle.

### 6.3.2 Supplemental Trimming Costs

Supplemental trimming costs are projected by the Tree Trimming Model based on curves derived in the model configuration stages.

In all supplemental scenarios, each service area was guaranteed their allocation of one quarter of the supplemental miles, with the remaining three-quarters of the miles getting targeted to where they were most needed.

### 6.3.3 Mid-Cycle Costs

There are four key assumptions relating to mid-cycle trimming activities:

- The cost premium for inspection and targeted trimming relative to cycle activities
- The timing of mid-cycle activities
- The portions of circuits to target
- The fraction of trees which will require mid-cycle intervention

Inspection-based activities come at a premium. There is first the cost of patrolling and inspecting the lines before vegetation management activities are taken, which must then be loaded into the costs of performing the actions in question. Second, relative to regular maintenance trimming, there are cost inefficiencies to trimming selectively. In regular maintenance trimming, vegetation crews can trim multiple trees each time they set up their vehicle and raise the bucket. In selective trimming, the ratio of setup time to actual wood removal goes up, further increasing the per-unit cost. Based on an analysis of corrective maintenance tickets, the TECO subject matter experts estimated that mid-cycle trimming would cost 80 percent more on a per-tree basis than routine trimming.

Mid-cycle activities are timed to promote the best possible performance out of the routine trimming initiative. Based on TECO subject matter expert input and considering the intervals between trimming in the baseline and enhanced scenarios, two years was selected as the optimal time for a mid-cycle inspection and associated vegetation management activities.

Mid-cycle activities will have similar impact in terms of overall restoration effort in a major event whether they occur on the feeder or lateral. Activities on the feeder will, however, protect more customers per tree outage avoided. With this in mind, TECO subject matter experts specified two possible scopes for Initiative 2 – feeder miles and all miles to be considered in that order.

The final component of scoping this cost was to predict the maximum number of trees to be targeted for mid-cycle activities as a result of the inspections. TECO subject matter experts estimated up to 25 percent of trees would grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. The analysis uses this figure but presumes that additional activities may be substituted for portions of the potential trimming, such as performing removals and the like, as long as the activities fit within the stipulated budget. As the cost per tree is 180% of regular trimming cost, and only 25 percent of trees can be targeted for mid-cycle activity, this should never amount to greater than 45% (180% * 25%) of the regular 4-year cycle budget.

### 6.3.4 Corrective Costs

TECO responds to approximately 4,000 corrective maintenance tickets annually, of which one third are related to tree limbs growing too close to the wires. The remainder are related to various forms of capital work, moving lines to accommodate construction, and the like. In total, the corrective maintenance tickets currently amount to $1.3 million per year, with TECO trimming to a four-year cycle. In prior filings, TECO estimated that moving from a three-year to a four-year cycle would result in a 30 percent increase in corrective maintenance tickets. Conversely, moving from four years back to three years would effectively revert the current $1.3 million budget to $1.0 million, or a roughly 23 percent reduction. Postulating that all growth-related tickets (33 percent) would be eliminated in a two-year cycle, the team fit a curve and generated a set of assumptions as follows, relative to the baseline 4-year scenario:

**Table-6-6: Cost Assumptions by Effective Cycle**

| Effective Cycle (years) | Cost Reduction | Resulting Cost |
|---|---|---|
| **4.00** | 0.0% | $1.30M |
| **3.75** | 7.0% | $1.21M |
| **3.50** | 13.0% | $1.13M |
| **3.25** | 18.5% | $1.06M |
| **3.00** | 23.0% | $1.00M |
| **2.75** | 26.7% | $0.95M |
| **2.50** | 29.6% | $0.91M |
| **2.25** | 31.7% | $0.89M |
| **2.00** | 33.0% | $0.86M |

### 6.3.5 Resource Premium Costs

Experience has shown that there is a limit to the rate at which TECO can expand its workforce without incurring some degree of premium cost. To account for this, the TTM Storm Module estimates the number of resources that would be required to do the Trimming, Mid-cycle and Corrective work in an assumed 2,000-hour work year, and applies a number of cost adjustment factors if that amount is significantly higher than the current size. Cost Premium calculations consider the maximum number of resources that can be added in a given year without offering overtime or a per diem premium, and the assumed productivity of new resources in their first year.

### 6.3.6 Day-to-Day Restoration Costs

A key output of the Tree Trimming Model is the anticipated reliability performance of the system due to vegetation-caused outages in each year of the analysis. The reliability predictions are produced through TTM's CI and CMI configuration curves, which are derived on the basis of several years of outage and tree trimming data.

Outages trigger restoration costs through the use of the dispatch function, line crews and tree crews. The average cost for responding to an outage is estimated at $1,300 and the calculated average number of customers interrupted per vegetation outage is 65, resulting in an estimated average cost per CI due to tree-caused outages of twenty dollars.

Annual restoration costs are estimated multiplying the SAIFI values generated by TTM by the number of customers served by TECO, and in turn multiplying that product by the estimate of $20 per customer interrupted.

### 6.3.7 Storm Restoration Costs

The TTM Storm Module projects storm restoration costs per year using a function which determines the fraction of customers who will experience power loss based on wind-speed experienced and the number of years since the circuit was last trimmed, an amalgam of annual windspeed probabilities derived from FEMA's Hazards-US dataset and an estimate of restoration cost per customer derived from TECO's recent experience with Hurricane Irma.

The TTM Storm Module's central equation is based on a study conducted in southern Florida around 2005 which determined that wind-driven tree outages are influenced by the length of time since last trim. The equation accepts as parameters the wind speed experienced and the number of years since the circuit was last trimmed. The equation returns a percentage which is then applied to the number of customers served by the circuit to come up with an estimate of customers interrupted. In cases of extremely high winds (150 mph and up) and long intervals since last trim, the equation can return values above 100 percent, which is taken to mean that while only 100 percent of the customers on a circuit will be interrupted, the effort to restore them will go beyond the usual cost per customer due to the multitude of damage locations on the circuit.

| Wind Gusts (3 second sustained @10m elevation) | Years Since Last Trim: 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| 40 | 0.19% | 0.48% | 0.83% | 1.21% | 1.68% | 2.08% |
| 45 | 0.27% | 0.69% | 1.18% | 1.73% | 2.32% | 2.96% |
| 50 | 0.38% | 0.94% | 1.61% | 2.37% | 3.18% | 4.06% |
| 55 | 0.50% | 1.25% | 2.15% | 3.15% | 4.24% | 5.40% |
| 60 | 0.65% | 1.63% | 2.79% | 4.09% | 5.50% | 7.01% |
| 65 | 0.82% | 2.07% | 3.53% | 5.20% | 6.99% | 8.91% |
| 70 | 1.03% | 2.58% | 4.43% | 6.49% | 8.74% | 11.13% |
| 75 | 1.27% | 3.18% | 5.43% | 7.99% | 10.74% | 13.69% |
| 80 | 1.54% | 3.88% | 6.61% | 9.69% | 13.04% | 16.61% |
| 85 | 1.84% | 4.63% | 7.93% | 11.63% | 15.64% | 19.93% |
| 90 | 2.19% | 5.49% | 9.42% | 13.80% | 18.57% | 23.66% |
| 95 | 2.57% | 6.46% | 11.07% | 16.23% | 21.84% | 27.82% |
| 100 | 3.00% | 7.54% | 12.92% | 18.93% | 25.47% | 32.45% |
| 105 | 3.47% | 8.72% | 14.93% | 21.92% | 29.48% | 37.56% |
| 110 | 3.99% | 10.03% | 17.19% | 25.20% | 33.90% | 43.19% |
| 115 | 4.56% | 11.46% | 19.63% | 28.79% | 38.73% | 49.35% |
| 120 | 5.18% | 13.02% | 22.32% | 32.71% | 44.01% | 56.07% |
| 125 | 5.86% | 14.72% | 25.23% | 36.98% | 49.74% | 63.38% |
| 130 | 6.59% | 16.58% | 28.38% | 41.59% | 55.95% | 71.29% |
| 135 | 7.38% | 18.54% | 31.78% | 46.58% | 62.66% | 79.84% |
| 140 | 8.23% | 20.68% | 35.44% | 51.95% | 69.88% | 89.04% |
| 145 | 9.15% | 22.98% | 39.38% | 57.72% | 77.64% | 98.93% |
| 150 | 10.13% | 25.44% | 43.60% | 63.90% | 85.95% | 109.52% |
| 155 | 11.17% | 28.06% | 48.10% | 70.50% | 94.84% | 120.84% |
| 160 | 12.29% | 30.87% | 52.91% | 77.55% | 104.31% | 132.91% |

**Figure 6-6: Expected Damage by Wind Gusts for a Given Year Since Last Trim**

The windspeed probabilities employed by the TTM Storm Module are derived from wind speed return values calculated by FEMA in their Hazards-US (HAZUS) package. HAZUS provides a geographically specific listing of windspeeds that can be expected to return to a given location every year, 10 years, 20 years, 50 years, and so on through 1,000 years based on an analysis of tropical storm tracks over several decades. Those data points are transformed to point probabilities for individual windspeeds, from which expectations for given ranges are calculated. The TTM Storm Module is loaded with probabilities every 10 miles from 55 miles per hour through 195 miles per hour, representing the probability of seeing windspeeds in the 50-60 mile per hour range, 60-70 mile per hour range and so on through to the 190-200 mile per hour range.

With an estimate of the expected number of customers to experience outages due to extreme weather events established, the final step is to multiply by the expected cost to restore customers. In Accenture's storm benchmark database, storm restoration is calculated based on total cost per customers out at peak. As illustrated below, while TECO experienced a grand total of about 328,000 customers out from Hurricane Irma, the number of customers out simultaneously was 213,000, as many quick wins are achieved early through switching and the restoration of substation and transmission issues. Approximately two thirds of this peak value are believed to be tree-caused.

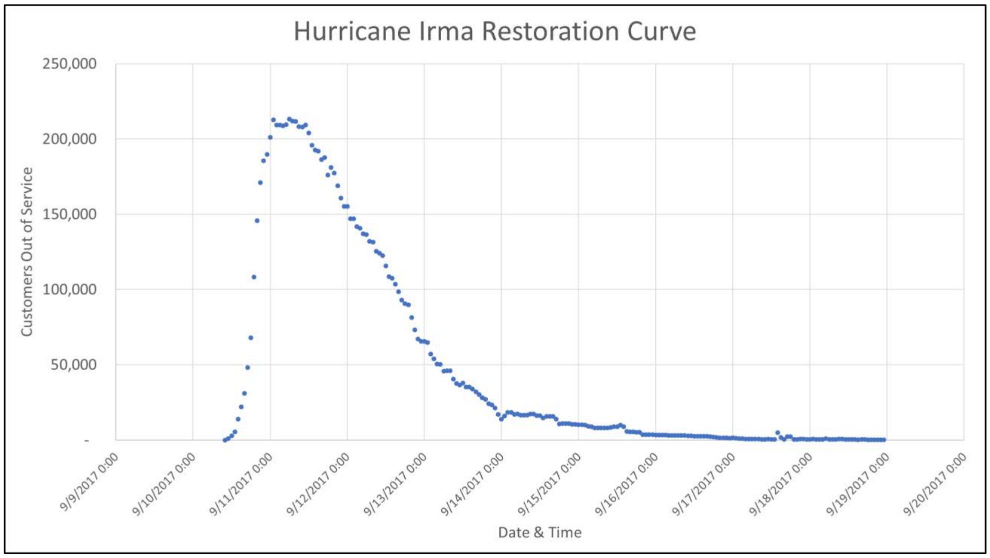


**Figure 6-7: TECO Restoration Curve for Hurricane Irma**

The peak number of customers out forms a more consistent denominator for cost per customer calculations, and in the case of TECO's experience with Irma this worked out to $389 per CI in line, tree, planning, logistics and other costs, which is in line with other Irma experiences in the State. Given the demand pressure on tree and line resources coming out of California's wildfire crisis, and general inflationary pressure, TECO's subject matter experts estimate that costs have risen by ten percent in the past two years, so the same restoration today would cost $424 per CI.

# 7 Work Plan

## 7.1 Baseline Summary

| Work Area | 2020 | | 2021 | | 2022 | | 2023 | |
|---|---|---|---|---|---|---|---|---|
| | Miles | Customers | Miles | Customers | Miles | Customers | Miles | Customers |
| CENTRAL | 260.3 | 43,997 | 262.1 | 44,336 | 260.0 | 51,889 | 260.1 | 52,612 |
| DADE CITY | 93.3 | 4,618 | 80.1 | 2,308 | 107.8 | 5,541 | 90.8 | 3,015 |
| EASTERN | 212.4 | 30,524 | 210.1 | 34,845 | 208.8 | 35,717 | 208.6 | 27,808 |
| PLANT CITY | 311.9 | 16,511 | 308.9 | 16,875 | 309.7 | 22,055 | 311.4 | 12,296 |
| SOUTH HILLSBOROUGH | 178.3 | 16,775 | 176.1 | 26,999 | 181.4 | 14,380 | 184.5 | 18,196 |
| WESTERN | 279.3 | 67,510 | 279.5 | 60,773 | 277.0 | 64,125 | 278.2 | 59,307 |
| WINTER HAVEN | 227.0 | 26,391 | 237.9 | 9,676 | 228.4 | 16,338 | 230.7 | 25,762 |
| Total | 1,562.6 | 206,326 | 1,554.6 | 195,812 | 1573.0 | 210,045 | 1,564.2 | 198,996 |

## 7.2 Supplemental Summary

| Work Area | 2020 | | 2021 | | 2022 | | 2023 | |
|---|---|---|---|---|---|---|---|---|
| | Miles | Customers | Miles | Customers | Miles | Customers | Miles | Customers |
| CENTRAL | 77.9 | 21,357 | 159.1 | 29,226 | 113.5 | 20,418 | 127.1 | 19,538 |
| DADE CITY | 99.9 | 5,208 | 6.2 | 484 | 127.6 | 5,578 | 44.9 | 681 |
| EASTERN | 99.8 | 18,598 | 153.3 | 12,341 | 72.9 | 8,794 | 149.8 | 18,918 |
| PLANT CITY | 76.7 | 9,702 | 25.2 | 2,443 | 202.2 | 8,347 | 31.1 | 3,579 |
| SOUTH HILLSBOROUGH | 15.3 | 2,264 | 20.5 | 2,427 | 20.2 | 3,236 | 138.9 | 28,399 |
| WESTERN | 15.7 | 3,926 | 82.8 | 13,024 | 112.4 | 20,376 | 155.8 | 27,165 |
| WINTER HAVEN | 16.8 | 1,277 | 63.1 | 5,063 | 43.2 | 5,784 | 53.2 | 7,950 |
| Total | 402.3 | 62,332 | 510.2 | 65,008 | 692.0 | 72,533 | 700.8 | 106,230 |

### 7.3 Mid-cycle Summary

| Work Area | 2020 | | 2021 | | 2022 | | 2023 | |
|---|---|---|---|---|---|---|---|---|
| | Miles Inspected | Customers | Miles Inspected | Customers | Miles Inspected | Customers | Miles Inspected | Customers |
| CENTRAL | 0.0 | 0 | 48.6 | 17,262 | 36.0 | 9,488 | 176.8 | 25,321 |
| DADE CITY | 0.0 | 0 | 2.8 | 1,293 | 5.1 | 904 | 0.0 | 0 |
| EASTERN | 0.0 | 0 | 17.3 | 4,730 | 34.5 | 12,007 | 115.3 | 16,234 |
| PLANT CITY | 0.0 | 0 | 18.0 | 8,234 | 12.0 | 7,191 | 231.0 | 12,380 |
| SOUTH HILLSBOROUGH | 0.0 | 0 | 51.7 | 16,233 | 23.0 | 13,900 | 82.1 | 3,925 |
| WESTERN | 0.0 | 0 | 58.8 | 27,318 | 53.3 | 19,073 | 171.2 | 27,479 |
| WINTER HAVEN | 0.0 | 0 | 45.9 | 20,663 | 32.1 | 14,565 | 241.5 | 7,779 |
| **Total** | **0.0** | **0** | **243.1** | **95,733** | **196.0** | **77,128** | **1017.9** | **93,118** |

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

**DOCKET NO. 20200067-EI**

# TAMPA ELECTRIC's 2020-2029 STORM PROTECTION PLAN

**TESTIMONY AND EXHIBIT**

**OF**

**REGAN B. HAINES**

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**FILED: APRIL 10, 2020**

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**REGAN B. HAINES**

**TABLE OF CONTENTS:**

**INTRODUCTION:**

**Q.** Please state your name, address, occupation and employer.

**A.** My name is Regan B. Haines. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Director, Asset Management, Project Management and System Planning.

**Q.** Please describe your duties and responsibilities in that position.

**A.** My duties and responsibilities include the governance and oversight of all Energy Delivery transmission and distribution assets. I am also responsible for developing and executing strategy and priorities for Energy Delivery's overall network for system planning, reliability planning and system maintenance. In addition, I am responsible for Energy Delivery's capital planning and budgeting, large project management, system root cause analysis, and benchmarking.

**Q.** Please describe your educational background and professional experience.

**A.** I graduated from Clemson University in June 1989 with a Bachelor of Science degree in Electrical Engineering and again in December 1990 with a Master of Science degree in Electrical Engineering specializing in Power Systems Engineering. I have been employed at Tampa Electric since 1998. My career has included various positions in the areas of Transmission and Distribution Engineering and Operations.

**Q.** What is the purpose of your direct testimony in this proceeding?

**A.** The purpose of my direct testimony is to explain six of the eight Storm Protection Programs in the company's proposed 2020-2029 Storm Protection Plan ("SPP" or "Plan"). I will also describe the Storm Protection Projects associated with these Programs as applicable. My testimony will describe how the company's Plan complies with Rule 25-6.030(3) by providing all the information required for each of these six Programs and their implementing Projects.

**Q.** Are you sponsoring any exhibits in this proceeding?

**A.** Yes. I have prepared an exhibit entitled, "Exhibit of Regan B. Haines." It consists of four documents and has been identified as Exhibit No. RBH-1, which contains the following documents:

- Document No. 1 provides Tampa Electric's – Proposed 2020-2029 Storm Protection Plan Projected Costs versus Benefits by Program.
- Document No. 2 provides the Project Detail for the Distribution Lateral Undergrounding Program.
- Document No. 3 provides the Project Detail for the Transmission Asset Upgrades Program.
- Document No. 4 provides the Project Detail for the Distribution Overhead Feeder Hardening Program.

**TAMPA ELECTRIC'S SERVICE AREA**

**Q.** Are there any parts of Tampa Electric's service area that were prioritized for enhancement, or any areas where enhancement would not be feasible, reasonable or practical, under the six Programs described in your testimony?

**A.** No. The company did not exclude any area of the company's existing transmission and distribution facilities for enhancement under these Programs due to feasibility, reasonableness, or practicality.

**TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION PLAN**

**Q.** Would you describe the Programs that support Tampa Electric's Storm Protection Plan?

**A.** Tampa Electric's proposed 2020-2029 Storm Protection Plan is comprised of eight distinct Programs. The Programs are:

1. Distribution Lateral Undergrounding
2. Vegetation Management
3. Transmission Asset Upgrades
4. Substation Extreme Weather Hardening
5. Distribution Overhead Feeder Hardening
6. Transmission Access Enhancement
7. Infrastructure Inspections
8. Legacy Storm Hardening Plan Initiatives

**Q.** You mentioned that you would be describing six of the eight Storm Protection Programs. Which Programs are you not describing?

**A.** I will not be describing the Vegetation Management or Transmission Access Enhancement Programs. The direct testimony of John H. Webster will cover those two Storm Protection Programs.

**Q.** How is your testimony organized?

**A.** For each Program I am describing, my testimony will explain how the company developed the information required by Rule 25-6.030(d)1-4, including: (1) a description of how the Program is designed to enhance existing transmission and distribution facilities, including an estimate of the resulting restoration in outage times and restoration costs; (2) actual or estimated start and completion dates of the program; (3) a cost estimate including capital and operating expenses; and (4) an analysis of costs and benefits.

**Q.** Will you testify regarding the information required by Rule 25-6.030(3)(d)5 – the criteria the company used to select and prioritize its proposed Storm Protection Programs?

**A.** No. The direct testimony of Gerard R. Chasse will describe the process Tampa Electric used to select and prioritize Programs.

**Q.** Will your testimony also address certain Storm Protection Projects?

**A.** Yes. In addition to explaining the required Program details, for each Program with Projects, my testimony will also explain how the company developed the required

Project-level details for the first year of the Plan, including: (1) actual or estimated construction start and completion dates; (2) a description of the affected facilities, including the number and type of customers served; and (3) a cost estimate including capital and operating expenses. My testimony will also describe how the company forecasted Project-level detail for the second and third years of the Plan.

**Q.** In the direct testimony of Gerard R. Chasse, he mentions that Tampa Electric used a consultant to assist with the development of the Plan. Why did Tampa Electric use this consultant?

**A.** Tampa Electric hired a consulting firm to help develop the company’s Plan. The company was looking for and found a consulting firm with expertise in the areas of T&D system hardening and cost-benefit analysis. The company also wanted an independent third-party review of our proposed SPP Programs and our methodology and prioritization approach. In addition, the company needed assistance with performing a thorough cost-benefit analysis. Tampa Electric selected 1898 & Co., part of Burns & McDonnell, which offered a very robust asset management modeling approach that would allow us to effectively analyze the storm impact risks associated with each component of the T&D system. Their model also gave us the capability to perform scenario analysis and ultimately prepare a robust cost-benefit analysis for several of our proposed Programs, including the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening and Distribution Overhead Feeder Hardening Programs. This analysis was critical as we prioritized Projects within each of these Programs and analyzed the costs and benefits of the Programs. In addition, 1898 gave us the ability to model the combined improvements from multiple Programs simultaneously, model multiple scenarios and optimize portfolio spend, and finally, gain confirmation that modeled benefits were appropriate, achievable and in range with the industry. The company believes that 1898 possessed the model needed to effectively perform the type of required analysis. Jason D. De Stigter from 1898 will provide direct testimony to more fully detail the approach taken for each of the Programs they supported.

**Q.** Please explain how Tampa Electric and 1898 & Co. prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather

Hardening and Distribution Overhead Feeder Hardening Programs?

**A.** The methodology used to develop the estimate of the reduction in outage times and restoration costs is addressed in detail in Jason D. De Stigter's direct testimony, but in general, 1898 developed a storm model that simulated 99 different storms scenarios and each scenario was modeled to identify which parts of the electric system are most likely to fail given each type of storm. The likelihood of failure is driven by the age and condition of the asset, the wind zone the asset is located within and the vegetation density around each conductor asset. 1898's Storm Impact Model also created an estimate of the restoration costs and Customer Minutes of Interruption ("CMI") associated with each potential Project for each storm scenario. Finally, the model calculated the benefit in terms of decreased restoration cost and reduced CMI if that Storm Protection Project were implemented per the company's hardening standards. This approach was repeated for every potential Storm Protection Project within each of these Programs. Finally, the estimated benefits of avoided restoration costs and outages were summed over the life of all hardened assets proposed for each Program during the 10 year plan and compared to the projected performance of the current assets or status quo. This comparison gave the company an estimated relative percentage reduction in restoration costs and outage times for each SPP Program. These estimates are included in my Exhibit No. RBH-1, Document No. 1 and are represented in terms of the relative benefit or improvement that the 10-year Program will provide. The benefits of a reduction in restoration costs and outage times are shown as a percentage improvement expected during extreme weather events or major event days when compared to the status quo.

**Q.** Please explain the methodology Tampa Electric used to prioritize the Projects the company is including in the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening and Distribution Overhead Feeder Hardening Programs?

**A.** The methodology used to develop the prioritization of Projects in these Programs is addressed in detail in Jason D. De Stigter's direct testimony. In general, we developed a Project cost estimate for each potential Project in our system that was based on several factors depending on the Program. For example, for distribution lateral undergrounding, factors such as the length of the line, location of the facilities (front or rear lot), number of transformers and customer services, etc. were considered. Secondly, we estimated the benefits each potential Project could provide by determining the savings of avoided restoration costs and the reduction in outage times or reduced customer minutes of interruption. The outage time reductions or savings were then converted to financial benefits utilizing the Department of Energy's Interruption Cost Estimator (ICE) calculator. The ICE Calculator is an electric reliability planning tool designed for electric reliability planners to estimate interruption costs and/or the benefits associated with reliability improvements. Both benefits were combined and a cost benefit NPV was calculated for each potential Project. The NPVs were then used to rank or prioritize each Project within a given SPP Program.

**Q.** Does the final ranking of projects in the SPP strictly follow 1898's prioritization?

**A.** No. The ranking serves as a guide, but the company will also apply operational experience and judgment when selecting Projects. This will help us to first, gain valuable experience early on in a Program by picking Projects that will ensure our procedures and approach are fully vetted with some of the less complex areas, and second, ensure that we are addressing all areas and communities equitably within our service territory.

**Q.** Did Tampa Electric prepare an analysis of the estimated costs and benefits of the Distribution Lateral Undergrounding, Transmission Asset Upgrades and Distribution Overhead Feeder Hardening Programs?

**A.** Yes. As I mentioned earlier, the company created cost estimates for each potential Project within each Program and then determined the benefit of each Project by using 1898’s model to compare its performance before and after hardening. The benefits of a reduction in restoration costs and outage times for all of the Projects planned for each Program are shown as a percentage improvement expected during extreme weather events or major event days when compared to the status quo. A table comparing the estimated costs and benefits for each Program is included as Exhibit No. RBH-1, Document No. 1.

**Q.** You stated previously that the company compared the estimated costs and benefits of the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening and Distribution Overhead Feeder Hardening Programs. How did the company use the Project-level costs and benefits described above to perform this comparison?

**A.** A detailed description of how the company used Project-level costs and benefits is addressed in Jason D. De Stigter’s direct testimony. In general, a cost benefit NPV was developed for each potential Project which was then used to first determine its relative cost effectiveness and then to rank or prioritize Projects within each of the Programs. As mentioned earlier, this established a ranked Project listing that the company will use together with its business and operational judgement to determine when Projects will be implemented. Then the estimated costs and benefits for all Projects selected for each Program during the 2020-2029 plan period were aggregated to determine the total costs and benefits of each Program illustrated in my Exhibit No. RBH-1, Document No. 1.

**Distribution Lateral Undergrounding**

**Q.** Please provide a description of the Distribution Lateral Undergrounding Program.

**A.** The primary objective of Tampa Electric’s Distribution Lateral Undergrounding Program is to increase the resiliency and reliability of the distribution system serving our customers during and following a major storm event by converting existing overhead distribution facilities to underground. Tampa Electric has approximately 6,250 miles of overhead distribution lines of which approximately 4,500 miles or 72% of the overhead distribution system are considered lateral lines or fused lines that branch off the main feeder lines. These lateral lines can be one, two or three phase lines and typically serve communities and neighborhoods.

**Q.** Did Tampa Electric work with 1898 to develop this Program?

**A.** Yes. The company worked with 1898 & Co. to prioritize all lateral lines utilizing a methodology that factors in the probability or likelihood of failure and the impact or consequence if a failure occurs during a major weather event. The company’s distribution system contains 787 circuits or feeders and over 18,000 lateral lines. While the company has experience converting small areas of overhead distribution facilities to underground, this is the first time it will do so in this scale.

**Q.** What role does community outreach play in an undergrounding Program?

**A.** Community and customer outreach will be critical to the success of this Program. The company has accordingly placed an emphasis on this. A comprehensive outreach process will be developed to work cooperatively with property owners and neighborhoods impacted by this Program.

**Q.** How does the company plan to implement this Program?

**A.** This SPP Program will include a ramp up of overhead to underground conversion Projects in 2020 and 2021 to help establish the best overall process to maintain moving forward as this Program will continue past the ten-year horizon of this plan. Using the lateral line ranking as a guide, the company has created Projects that it will undertake each year. The company’s plan is to develop an organization and structure that supports undergrounding 100-150 miles annually over the period 2022-2029. For plan year 2020 and 2021, the company plans to underground a total of 90-100 miles. This will include converting the existing overhead lateral primary, lateral secondary and service lines to underground.

**Q.** Please explain how Tampa Electric’s Distribution Lateral Undergrounding Program will enhance the utility’s existing transmission and distribution facilities?

**A.** This Program will provide many benefits including reducing the number of outages and momentary interruptions experienced during extreme weather events and day-to-day conditions, reducing the amount of storm damage, and reducing restoration costs. Historically, 94 percent of the outages occurring on the company’s overhead distribution system originate from an event on an overhead distribution lateral line. In addition, a significant amount of a utility’s restoration efforts deals with failures on lateral lines following major storm events. Many of the lateral lines in the older areas served are in the rear of customers’ homes. These “rear lot” lateral lines are more likely to be impacted during a storm given vegetation and are more difficult to access and restore when they are impacted. Given that most of the failures experienced during major storm events, as well as day to day, originate on a lateral line, the primary objective of this Program is to underground the lateral lines that have the highest likelihood of failing and that also create the most significant impact during a major storm event. Comparatively, very few, if any outages have originated on underground facilities during the recently experienced named storms and only 6% during blue sky, day-to-day conditions. By undergrounding these overhead lateral lines, the risk of failure during a major storm event should be significantly mitigated.

**Q.** Did Tampa Electric prepare a list of Distribution Lateral Undergrounding Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

**A.** Yes, the list of Distribution Lateral Undergrounding Projects for 2020 and their associated starting and projected completion dates is included in Appendix A of the Plan and in my Exhibit No. RBH-1, Document No. 2. The company has also developed a very preliminary list of Projects for 2021. Given that this is a new Program for the company, the list of Projects selected for 2020 and 2021 were those identified from the prioritized list that will increase the company’s chances of early success while providing the most benefit to customers.

**Q.** Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

**A.** Yes, a description of facilities affected by Project is included in my Exhibit No. RBH-1, Document No. 2. For this SPP Program, this will include a unique Project identifier, the number of and type of customers served by the facilities, and the number of miles of overhead line converted to underground for each Project.

**Q.** Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

**A.** Yes. The company has developed cost estimates for each Project within this Program for 2020 and 2021 and then totaled those estimates to derive the annual cost estimates for the Program. The company utilized several characteristics of the existing overhead facilities targeted for conversion to develop the cost estimates for each Project including, the number of phases involved, the length of the line, and location of the facilities (front or rear lot), etc. Based on the results of 1898's budget optimization model, the company then estimated the number of Projects it expects to complete in years 2022-2029 with average Project cost estimates to develop the annual Program costs in those years. The estimated costs for this Program include \$8M in 2020, \$80M in 2021 and then approximately \$100M-\$120M in each year 2022-2029. There were no incremental O&M costs associated with this Program. The table below sets out the estimated number of Projects and annual costs for 2020-2022.

| | Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 24 | $8.0 |
| 2021 | 281 | $79.5 |
| 2022 | 316 | $108.1 |

**Transmission Asset Upgrades**

**Q.** Please provide a description of the Transmission Asset Upgrades Program?

**A.** The main objective of this SPP Program is to address the vulnerability that our remaining wood transmission poles pose on the grid by systematically upgrading them to a higher strength steel or concrete pole. Tampa Electric plans to replace all existing transmission wood poles with non-wood material over the next ten years. The company has identified 131 of its existing 217 transmission circuits that have at least one existing wooden pole and will conduct replacement of those remaining transmission wood poles on an entire circuit basis.

**Q.** Please explain how Tampa Electric's Transmission Asset Upgrade Program will enhance the utility's existing transmission and distribution facilities?

**A.** Tampa Electric has over 1,000 miles of overhead transmission lines at voltage levels of 230kV, 138kV and 69kV. While the company experiences far fewer transmission outages and pole failures during major storm events than on the distribution system, an outage on the transmission system can have far greater impact and significance. The vast majority of these pole failures are associated with wood poles. Of the ten transmission poles replaced due to Hurricane Irma in 2017, nine were wooden poles with no previously identified deficiencies that would warrant the pole to be replaced under the existing Storm Hardening Plan Initiative. The company has already made significant progress in reducing storm-related transmission outages through implementation of Extreme Wind Loading design and construction standards. In the early 1990s, Tampa Electric changed its standards and began building all new transmission circuits with non-wood structures. Today, approximately 80 percent of Tampa Electric's transmission system is constructed of steel or concrete poles/structures. The remaining 20 percent, however, are still comprised of wood poles installed over 30 years ago.

Replacing the remaining wood transmission wood poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, and more robust, wind loading standards then required at the time of installation. This will greatly reduce the likelihood of a failure during a major storm event.

**Q.** Did Tampa Electric prepare a list of Transmission Asset Upgrades Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

**A.** Yes, the list of Transmission Asset Upgrades Projects for 2020 and their associated starting and projected completion dates is included in Appendix C of the Plan and in my Exhibit No. RBH-1, Document No. 3. The company is planning 21 projects in 2020 and has identified a very preliminary list of 35 projects for 2021. The remaining transmission circuits with wood poles were prioritized and scheduled for upgrade in the years 2022-2029.

**Q.** Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

**A.** Yes, in my Exhibit No. RBH-1, Document No. 3, the description of the affected facilities for this Program include the total number of wood poles replaced on a circuit basis for each Project. Given that the high voltage transmission system is designed to transmit power over long distances to end-use distribution substations, Tampa Electric does not attribute customer counts directly to individual transmission lines.

**Q.** Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

**A.** Yes. The company has developed cost estimates for each Project within this Program for 2020 and 2021 and then totaled those estimates to derive the annual cost estimates for the Program. The company utilized its experience of average costs to upgrade a wood transmission pole to non-wood and the number of poles associated with each Project to develop the cost estimates. The company then estimated the number of Projects it expects to complete in years 2022-2029 with average Project cost estimates to develop the annual Program costs in those years. The estimated costs for this Program include $5.6M in 2020, $15.2M in 2021 and then approximately $15M in each year 2022-2029. There were no incremental O&M costs associated with this Program. The table below sets out the estimated number of Projects and estimated annual costs for this Program for 2020-2022.

| | Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 21 | $5.6 |
| 2021 | 35 | $15.2 |
| 2022 | 28 | $15.0 |

**Substation Extreme Weather Hardening**

**Q.** Please provide a description of the Substation Extreme Weather Hardening Program?

**A.** The primary objective of this Program is to harden and protect the company’s substation assets that are vulnerable to flood or storm surge. This Program will minimize outages, reduce restoration times and enhance emergency response during extreme weather events. The company has identified 59 of its 216 substations that have some level of risk to flood or surge. 1898 modeled these 59 substations and prioritized based on the expected benefits of mitigation after hardening each with a flood wall solution. Utilizing this approach, 1898's model selected 11 substation hardening projects for the SPP Plan. Surprisingly, 1898's model indicated that the substation hardening projects account for a sizable restoration benefit while requiring a small percentage of the Plan's capital investment. Given this dramatic benefit to cost ratio, the company decided that further evaluation and assessment of this Program is needed. The company plans to perform a study utilizing a third party consultant that specializes in substation hardening and asset management in 2021 to evaluate various substation hardening solutions and assess the potential vulnerability of the identified substations to extreme weather, including flooding or storm surge. The results of the study will include a recommendation for each substation to be hardened, including the most cost effective hardening solution identified for each and a cost-benefit analysis. The study is estimated to cost around $250,000 and will produce a list of prioritized substation hardening projects.

**Q.** Please explain how Tampa Electric's Substation Extreme Weather Protection Program will enhance the utility's existing transmission and distribution facilities?

**A.** This Program will increase the resiliency and reliability of the substations through measures such as permanent or temporary barriers, elevating substation equipment, or relocating facilities to areas that are less prone to flooding. For those substations that are located closest to the coastline and of greatest risk, substation hardening efforts will eliminate or mitigate the impact of water intrusion due to storm surge into the substation control houses and equipment. By avoiding these types of impacts, restoration costs will certainly be reduced as will outage times.

**Q.** Please explain how Tampa Electric prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Substation Extreme Weather Protection Program?

**A.** Yes. Installing either permanent/temporary barriers, elevating substation equipment, or relocating facilities to areas that are less prone to flooding, will reduce restoration costs and times, as substation control houses and equipment would not exposed to major saltwater intrusion due to storm surge and/or flooding. If hardening efforts are not implemented, it would take Substation personnel or contractors an extremely long amount of time to flush equipment with clean water and air dry the equipment. Each piece of equipment would then need to be tested before it is placed back into service. All of these efforts will lead to significantly higher restoration costs and longer outage times. 1898's model was utilized to estimate the benefits in reduced restoration costs and outage times as previously explained.

**Q.** Did Tampa Electric prepare a list of Substation Extreme Weather Protection Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

**A.** The company does not propose any substation projects for 2020.

**Q.** Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

**A.** The company has not proposed any projects in 2020 but has identified 11 substations that have the greatest risk of impact due to flood or surge by an extreme weather event based on the preliminary analysis. The planned study will further refine this list and produce a project list and implementation plan.

**Q.** Would you explain in detail the methodology Tampa Electric used in prioritizing the projects the company is including in this Program?

**A.** The detailed engineering study the company plans to conduct will produce a list of recommendations including a prioritized list of substations to harden and the methodology utilized.

**Q.** Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

**A.** The company estimates that the study will cost around $250,000. The planned study will produce a project list with project cost estimates and the implementation plan.

**Q.** Did Tampa Electric prepare an estimate of benefits (reduction in outage time, reduction in extreme weather restoration cost) for the projects the company is planning on initiating for this Substation Extreme Weather Hardening Program?

**A.** The company has not proposed any projects in 2020, however, the planned engineering study will provide a list of projects and an estimate of costs and benefits for each proposed substation hardening project.

**Q.** Did Tampa Electric prepare a comparison of the estimated costs and benefits of the Program?

**A.** The scope of the planned engineering study will include a recommended list of proposed hardening projects and a comparison of the estimated costs and benefits of the Program.

**Distribution Overhead Feeder Hardening**

**Q.** Please provide a description of the Distribution Overhead Feeder Hardening Program?

**A.** Tampa Electric’s distribution system includes feeders, also referred to as mainline or backbone, and laterals, which are tap lines off the main feeder line. The feeder is the main line that originates from the substation and is the most critical to ensuring power is reliably delivered to our customers one it leaves the substation. While the company has hardened some of its feeders that serve critical customers, this SPP Program will expand that effort to include some of our highest priority feeders, starting with those that have the worst historical day-to-day performance and performance during major storm events, those with the highest likelihood of failure, and those that would present the greatest impact if an outage were to occur.

**Q.** How will this Program harden the company’s feeders?

**A.** The Distribution Overhead Feeder Hardening Program includes strategies to further enhance the resiliency and reliability of the distribution network by further hardening the grid to minimize interruptions and reduce customer outage counts during extreme weather events and abnormal system conditions. These include stronger/hardened poles and facilities, installation of switching equipment to allow for automatic isolation of damaged facilities, upgrading of small wire conductor to ensure automatic service restoration is not limited by capacity constraints and the use of new equipment to minimize the interruption of service during atypical system configurations.

**Q.** What switching equipment does the company plan to install as a part of this Program?

**A.** The company will install reclosers and trip savers to minimize the number of customers interrupted during events as well as reduce the outage time for customers. This equipment will allow for the automatic isolation of faults on the system and then ultimately allow the network to re-configure itself real-time without operator intervention.

**Q.** How does the company plan to harden poles on feeder lines?

**A.** Hardening these feeders will include upgrading the poles older than 35 years of age, smaller than class 2 and ensuring the feeders meet NESC extreme wind loading standards along the feeder to increase the overall resiliency of the feeder. As an example, concrete poles that have a higher wind loading capacity may be utilized at key locations on the feeder such as switch, recloser, 3-phase transformer bank and capacitor bank locations. Additional steps that will be taken to harden the feeders and reduce restoration times will be installing sectionalizing switching devices, fault current sensors/indicators, and creating circuit ties to allow for automation.

**Q.** Please explain how Tampa Electric’s Distribution Overhead Feeder Hardening Program will enhance the utility’s existing transmission and distribution facilities?

**A.** The Distribution Overhead Feeder Hardening Program will enhance the resiliency of the distribution system by increasing the strength of the poles at most risk of failing during a major weather event as well as the poles at key locations along the feeder that would cause the greatest impact if a failure occurred. Tampa Electric has approximately 800 distribution feeders that serve near 1,000 customers on average each so mitigating the potential of an outage on these feeders is critical to minimizing customer outages. In addition, the company plans to add fault detection, isolation and restoration devices on feeders, which will significantly reduce the number of customers experiencing an outage during an event and allow those that do to be restored significantly quicker.

**Q.** Did Tampa Electric prepare a list of Distribution Overhead Feeder Hardening Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

**A.** Yes, the list of Distribution Overhead Feeder Hardening Projects for 2020 and their associated starting and projected completion dates is included in Appendix D of the

Plan and in my Exhibit No. RBH-1, Document No. 4. The company has a very preliminary list of Projects for 2021 and has identified how many distribution feeders the company plans to harden in the years 2022-2029.

**Q.** Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

**A.** Yes, included in Appendix D of the Plan and in my Exhibit No. RBH-1, Document No. 4, the description of facilities affected include a unique Project identifier, the number and type of major equipment upgraded or installed, and the number and type of customers served by the facilities.

**Q.** Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

**A.** Yes. The company has developed cost estimates for each Project within this Program for 2020 and 2021 and totaled those estimates to derive the annual cost estimates for the Program. The company first defined the attributes of a hardened feeder and then applied the new criteria to each potential overhead feeder to develop its cost estimate to harden. The estimated costs for each Project reflect bringing that feeder up to the new hardened standard which includes poles meeting NESC Extreme Wind loading criteria, no poles lower than a class 2, no conductor size smaller than 336 ACSR, single phase reclosers or trip savers on laterals, feeder segmented and automated with no more than 200-400 customers per section and no segment longer than 2-3 miles, no more than two to three MWs of load served on each segment, and circuit ties to other feeders with available switching capacity. The company then estimated the number of Projects it expects to complete in years 2022-2029 with average Project cost estimates to develop the annual Program costs in those years. The estimated costs for this Program include $6.5M in 2020, $15.4M in 2021, 29.6M in 2022, and then approximately $33M in each year 2023-2029. There were no incremental O&M costs associated with this Program. The table below includes the estimated number of Projects and estimated costs per year for 2020-2022.

| | Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 5 | $6.5 |
| 2021 | 18 | $15.4 |
| 2022 | 13 | $29.6 |

**Infrastructure Inspections**

**Q.** Please provide a description of the Infrastructure Inspections Program?

**A.** Thorough inspections of Tampa Electric's poles, structures and substations is critical for ensuring the system is maintained and in a resilient state should the company experience a major storm event. This SPP Program involves the inspections performed on the company's T&D infrastructure including all wooden distribution and transmission poles, transmission structures and transmission substations, as well as the audit of all joint use attachments.

**Q.** Does Tampa Electric currently carry out infrastructure inspections?

**A.** Yes. Tampa Electric's Infrastructure Inspection Program is part of a comprehensive program initiated by the Florida Public Service Commission for Florida investor-owned electric utilities to harden the electric system against severe weather and to identify unauthorized and unnoticed non-electric pole attachments which affect the loadings on poles. This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No.

20060078-EI which requires each investor-owned electric utility to implement an inspection program of its wooden transmission, distribution and lighting poles on an eight-year cycle based on the requirements of the NESC. This Program provides a systematic identification of poles that require repair or replacement to meet strength requirements of NESC. Tampa Electric performs inspections of all wood poles on an eight-year cycle. Tampa Electric has approximately 290,000 wooden distribution and lighting poles and 25,700 transmission poles and structures that are part of an inspection program. Approximately 12.5 percent of the known pole population will be targeted for inspections annually although the actual number of poles may vary from year to year due to recently constructed circuits, de-energized circuits, reconfigured circuits, etc.

**Q.** How will the Infrastructure Inspection Program identify potential system issues?

**A.** The Tampa Electric Transmission System Inspection Program identifies potential system issues along the entire transmission circuit by analyzing the structural conditions at the ground line and above ground as well as the conductor spans. Formal inspection activities included in the Program are ground line inspection, ground patrol, aerial infrared patrol, above ground inspection and transmission substation inspections. Typically, the ground patrol, aerial infrared patrol and substation inspections are performed every year while the above ground inspections and the ground line inspection are performed on an eight-year cycle.

The company also performs joint use audits and inspections to mitigate the impact unknown foreign attachments could create by placing additional loading on a facility. All Tampa Electric joint use agreements have provisions that allow for periodic inspections and/or audits of all joint use attachments to the company's facilities to be paid for by the attaching entities.

**Q.** Please explain how Tampa Electric's Infrastructure Inspections Program will enhance the utility's existing transmission and distribution facilities?

**A.** Timely inspections and identification of required maintenance items can greatly reduce the impact of major storm events to the transmission and distribution system. Given that poles are critical to the integrity of the transmission and distribution grid, pole inspections are a key component of this SPP Program. Pole failures during a major storm event can cause a significant impact since there is high probability that the equipment attached to the pole will also experience damage. Cascading failures of other poles will also likely occur. Specifically, wood poles pose the greatest risk of failure and must be maintained and eventually replaced given they are prone to deterioration. The 8-year wood pole inspection requirement put in place by the Florida Public Service Commission is aimed at identifying any problems with a pole so they can be mitigated before they cause a problem during a major storm event. In addition, the other FPSC required inspections included in this SPP Program are also aimed at identifying compromised equipment that may create a vulnerability so that they can be addressed prior to causing a problem during a major storm event.

**Q.** Please explain how Tampa Electric prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Infrastructure Inspections Program?

**A.** While Tampa Electric did not prepare estimates of the reduction in outage times and restoration costs for this Program, as I previously discussed, inspections play a critical role in identifying issues with infrastructure and facilities so appropriate repairs can be made before a failure and resulting outage occurs. By doing so, the number of outages and outage times, not only during a major storm event, but also during day-to-day operations will be significantly reduced. In addition, planned repairs of equipment and facilities identified through an inspection are significantly less costly than restoring after a failure or following a major storm event.

**Q.** Did Tampa Electric prepare a list of Infrastructure Inspections Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

**A.** Tampa Electric conducts thousands of inspections each year so rather than identify various projects, the company has identified the number of inspections by type planned for 2020 – 2022 along with the estimated spend. The table included below sets out this information. Typically, these inspections are conducted throughout the year and have no specific start and completion date except for the bulk electric transmission and critical 69kV transmission substation and line inspections which are inspected first and prior to the peak of hurricane season each year.

| Projected Number of Infrastructure Inspections | | | |
|---|---|---|---|
| | **2020** | **2021** | **2022** |
| **Joint Use Audit** | Note 1 | | |
| **Distribution** | | | |
| Wood Pole Inspections | 22,500 | 22,500 | 35,625 |
| Groundline Inspections | 13,275 | 13,275 | 21,018 |
| **Transmission** | | | |
| Wood Pole/Groundline Inspections | 702 | 367 | 707 |
| Above Ground Inspections | 2,949 | 3,895 | 3,396 |
| Aerial Infrared Patrols | Annually | Annually | Annually |
| Ground Patrols | Annually | Annually | Annually |
| Substation Inspections | Annually | Annually | Annually |

**Q.** Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

**A.** As previously mentioned, Tampa Electric conducts thousands of inspections each year and has not identified specific projects or affected facilities. The company has identified the number of inspections by type planned for 2020 – 2022. While all customers will certainly benefit from this SPP Program, it is not practical to list specific customers or type of customers benefiting from a particular inspection.

**Q.** Would you explain in detail the methodology Tampa Electric used in prioritizing inspections?

**A.** Tampa Electric typically prioritizes its inspections by age or date of last inspection. Other criteria used to prioritize when inspections are performed include; bulk electric transmission and critical 69kV transmission substations and lines are inspected first and prior to the peak of hurricane season each year, circuits are patrolled based on their criticality or priority ranking, and finally, aerial infrared scans are scheduled in the summer time when load is highest which improves the accuracy of the results.

**Q.** Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

**A.** Yes. This can be located in the table below. The estimated costs for this Program include $1.2M in 2020, $1.5M in 2021 and then approximately $1.5M in each year 2022-2029. All costs associated with this Program are O&M.

| Projected Costs of Infrastructure Inspections (in thousands) | | | |
|---|---|---|---|
| | **2020** | **2021** | **2022** |
| **Distribution** | | | |
| Wood Pole/Groundline Inspections | $708 | $1,000 | $1,020 |
| **Transmission** | | | |
| Wood Pole/Groundline Inspections | $60 | $61 | $62 |
| Above Ground Inspections | $10 | $10 | $10 |
| Aerial Infrared Patrols | $110 | $112 | $114 |
| Ground Patrols | $145 | $148 | $151 |
| Substation Inspections | $140 | $143 | $146 |

**Q.** Did Tampa Electric prepare a comparison of the estimated costs and benefits of the Program?

**A.** Yes. The company has provided the costs associated with this Program and a description of the benefits provided.

**Legacy Storm Hardening Initiatives**

**Q.** Please provide a description of the Legacy Storm Hardening Initiatives?

**A.** The company plans to continue several well-established in place Storm Hardening Plan activities, referred to here as

Legacy Storm Hardening Plan Initiatives. Tampa Electric believes these Initiatives will continue to offer the storm resiliency benefits previously identified by the Commission. These Initiatives include a Geographical Information System, Post-Storm Data Collection, Outage Data - Overhead and Underground Systems, Increase Coordination with Local Governments, Collaborative Research, Disaster Preparedness and Recovery Plan and Distribution Pole Replacements.

Tampa Electric’s Geographic Information System (“GIS”) will continue to serve as the foundational database for all transmission, substation and distribution facilities. Regarding Post-Storm Data Collection, Tampa Electric has a formal process in place to randomly sample and collect system damage information following a major weather event. Tampa Electric has a Distribution Outage Database that it uses to track and store overhead and underground system outage data. Tampa Electric has an Emergency Preparedness team and representatives that will continue to focus on maintaining existing vital governmental contacts and participating on committees to collaborate in disaster recovery planning, protection, response, recovery and mitigation efforts. Tampa Electric will also continue to participate in the collaborative research effort with

Florida's other investor-owned electric utilities, several municipals and cooperatives to further the development of storm resilient electric utility infrastructure and technologies to reduce storm restoration costs and customer outage times. Tampa Electric will continue to maintain and improve its Disaster Preparedness and Emergency Response Plans and be active in many ongoing activities to support the improved restoration of the system before, during and after storm activation. Tampa Electric's distribution pole replacement initiative starts with the company's distribution wood pole and groundline inspections and includes restoring, replacing and/or upgrading those distribution facilities identified to meet or exceed the company's current storm hardening design and construction standards.

**Q.** Please explain how Tampa Electric's Legacy Storm Hardening Plan Initiatives will enhance the utility's existing transmission and distribution facilities?

**A.** As I've mentioned, all of these initiatives are well-established and have been in place since the Commission determined that they should be implemented and would provide benefits by enhancing the transmission and distribution system, reducing restoration costs and/or customer outage times.

**Q.** Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

**A.** Yes. In the table below, the company summarizes the expected capital and operating expenses for these initiatives during the 2020-2022 period. Tampa Electric plans to invest $9.42M in 2020, $11.18M in 2021 and $14.72M in 2022 of capital for distribution pole replacements. There is an associated operating expense of $520k in 2020, $620k in 2021 and $810k in 2022 for this activity. In addition, the company plans to incur $300k per year 2020-2022 in operating expenses for Disaster Preparedness and Emergency Response activities.

| | Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions) | |
|---|---|---|
| | Disaster Preparedness and Recovery Plan | Distribution Pole Replacements |
| 2020 | $0.3 | $9.9 |
| 2021 | $0.3 | $11.8 |
| 2022 | $0.3 | $15.5 |

**ADHERENCE TO F.A.C. RULES AND STATUTORY REQUIREMENTS**

**Q.** Does Tampa Electric's 2020-2029 Storm Protection Plan include all of the Program-level detail required by Rule 25-6.030(3)(d) and the Project-level detail required by Rule 25-6.030(3)(e)?

**A.** Yes. The Plan includes all the required Program-level detail for the six Storm Protection Programs described in my testimony. The Plan also includes the necessary Project-level detail for the Programs that contain Storm Protection Projects.

**CONCLUSIONS**

**Q.** Please summarize your direct testimony.

**A.** My testimony demonstrates that the six Programs I've discussed in Tampa Electric's proposed 2020-2029 Storm Protection Plan are consistent with Rule 25-6.030(3)(d)-(e), F.A.C. My testimony also demonstrates that these Programs will reduce restoration costs and outage times and enhance reliability in a cost-effective manner.

**Q.** Should Tampa Electric's proposed Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder

Hardening, Infrastructure Inspections, and Legacy Storm Hardening Programs be approved?

**A.** Yes. These Programs should be approved. These Programs meet the requirements of Rule 25-6.030 and they are designed to strengthen the company's infrastructure to withstand extreme weather conditions, reduce restoration costs, reduce outage times, improve overall reliability and increase customer satisfaction in a cost-effective manner.

**Q.** Does this conclude your testimony?

**A.** Yes.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**WITNESS: HAINES**

# EXHIBIT

# OF

# REGAN B. HAINES

**47**

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**EXHIBIT NO. RBH-1**
**WITNESS: HAINES**
**DOCUMENT 1**
**PAGE 1 OF 1**
**FILED: 04/10/2020**

| Tampa Electric - Proposed 2020-2029 Storm Protection Plan<br>Projected Costs versus Benefits | | | | | | |
|---|---|---|---|---|---|---|
| Storm Protection Program | Projected Costs (in Millions) | | Projected Reduction in Restoration Costs (Approximate Benefits in Percent) | Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent) | Program Start Date | Program End Date |
| | Capital | O&M | | | | |
| Distribution Lateral Undergrounding | $976.8 | $0.0 | 33 | 44 | Q2 2020 | After 2029 |
| Vegetation Management | $0.0 | $279.3 | 21 | 22 to 29 | Q2 2020 | After 2029 |
| Transmission Asset Upgrades | $148.9 | $3.0 | 90 | 13 | Q2 2020 | 2029 |
| Substation Extreme Weather | $32.4 | $0.0 | 70 to 80 | 50 to 65 | Q1 2021 | After 2029 |
| Distribution Overhead Feeder | $289.7 | $8.9 | 38 to 42 | 30 | Q2 2020 | After 2029 |
| Transmission Access Enhancements | $14.8 | $0.0 | 10 | 74 | Q1 2021 | After 2029 |

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**Tampa Electric's Distribution Lateral Undergrounding - Year 2020 Details**

| Project ID | Circuit No. | Specific Project Detail | | Customers | | | | Priority Customers | Project Start Qtr | Construction | | Project Cost in 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | OH to UG Length Converted (miles) | Poles | Residential | Small C&I | Large C&I | Total | | | Start Qtr | End Qtr | |
| Lateral Hardening-Fuse-60588225 | 13174 | 0.29 | 15 | 374 | 34 | 1 | 409 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $125,235 |
| Lateral Hardening-Fuse-10786382 | 14040 | 0.23 | 13 | 98 | 6 | 2 | 106 | 10 | Q2 2020 | Q3 2020 | Q4 2020 | $150,431 |
| Lateral Hardening-Fuse-90755954 | 13454 | 0.30 | 23 | 292 | 21 | 1 | 314 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $238,629 |
| Lateral Hardening-Fuse-60451701 | 13174 | 0.24 | 14 | 301 | 11 | 2 | 314 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $230,114 |
| Lateral Hardening-Fuse-10933151 | 13897 | 0.79 | 33 | 64 | 20 | 1 | 85 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $221,051 |
| Lateral Hardening-Fuse-92421291 | 13972 | 0.44 | 23 | 379 | 6 | 1 | 386 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $248,973 |
| Lateral Hardening-Fuse-92881445 | 13710 | 0.45 | 32 | 158 | 17 | 0 | 175 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $401,397 |
| Lateral Hardening-Fuse-92599119 | 13390 | 0.72 | 46 | 266 | 27 | 3 | 296 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $750,732 |
| Lateral Hardening-Fuse-92407065 | 13815 | 0.38 | 15 | 12 | 3 | 1 | 16 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $68,399 |
| Lateral Hardening-Fuse-93019714 | 13840 | 0.13 | 9 | 39 | 2 | 0 | 41 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $51,112 |
| Lateral Hardening-Fuse-92634300 | 14032 | 0.31 | 21 | 306 | 10 | 2 | 318 | 1 | Q2 2020 | Q3 2020 | Q4 2020 | $390,745 |
| Lateral Hardening-Fuse-60287236 | 13509 | 0.15 | 14 | 144 | 14 | 0 | 158 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $175,078 |
| Lateral Hardening-Fuse-60182741 | 13312 | 0.15 | 15 | 52 | 11 | 7 | 70 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $101,387 |
| Lateral Hardening-Fuse-90241880 | 13972 | 0.90 | 49 | 130 | 7 | 6 | 143 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $687,129 |
| Lateral Hardening-Fuse-10643541 | 13390 | 1.17 | 67 | 221 | 22 | 2 | 245 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $1,095,650 |
| Lateral Hardening-Fuse-10786374 | 14040 | 0.27 | 16 | 205 | 13 | 0 | 218 | 11 | Q2 2020 | Q3 2020 | Q4 2020 | $334,434 |
| Lateral Hardening-Fuse-92829453 | 13961 | 0.34 | 25 | 447 | 3 | 2 | 452 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $292,496 |
| Lateral Hardening-Fuse-91406672 | 13836 | 0.35 | 25 | 91 | 6 | 0 | 97 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $248,786 |
| Lateral Hardening-Fuse-90288627 | 13815 | 0.88 | 32 | 51 | 9 | 0 | 60 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $423,948 |
| Lateral Hardening-Fuse-91432109 | 13071 | 0.14 | 15 | 20 | 5 | 0 | 25 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $163,279 |
| Lateral Hardening-Fuse-90738378 | 13071 | 0.16 | 20 | 296 | 35 | 0 | 331 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $145,327 |
| Lateral Hardening-Fuse-90911087 | 13724 | 0.54 | 32 | 31 | 4 | 0 | 35 | 6 | Q2 2020 | Q3 2020 | Q4 2020 | $423,395 |
| Lateral Hardening-Fuse-93026469 | 13815 | 0.49 | 15 | 27 | 2 | 0 | 29 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $375,085 |
| Lateral Hardening-Fuse-10629014 | 13146 | 0.54 | 30 | 91 | 6 | 0 | 97 | 0 | Q2 2020 | Q3 2020 | Q4 2020 | $608,468 |

**Tampa Electric's Transmission Asset Upgrades - Year 2020 Details**

| Project ID | Circuit No. | Pole Count | Project Start Month | Construction Start Month | Construction End Month | Project Cost in 2020 |
|---|---|---|---|---|---|---|
| Transmission Upgrades-69 kV-66654 | 66654 | 10 | May-20 | Jul-20 | Jul-20 | $317,000 |
| Transmission Upgrades-69 kV-66840 | 66840 | 34 | May-20 | Jul-20 | Aug-20 | $1,077,800 |
| Transmission Upgrades-69 kV-66007 | 66007 | 43 | Jun-20 | Aug-20 | Aug-20 | $1,363,100 |
| Transmission Upgrades-69 kV-66019 | 66019 | 21 | Jul-20 | Sep-20 | Oct-20 | $665,700 |
| Transmission Upgrades-69 kV-66425 | 66425 | 3 | Jul-20 | Oct-20 | Oct-20 | $95,100 |
| Transmission Upgrades-138/230 kV-230403 | 230403 | 5 | Jul-20 | Oct-20 | Oct-20 | $105,700 |
| Transmission Upgrades-69 kV-66413 | 66413 | 5 | Jul-20 | Oct-20 | Oct-20 | $158,500 |
| Transmission Upgrades-69 kV-66046 | 66046 | 30 | Jul-20 | Oct-20 | Nov-20 | $939,900 |
| Transmission Upgrades-69 kV-66059 | 66059 | 2 | Aug-20 | Nov-20 | Nov-20 | $63,400 |
| Transmission Upgrades-138/230 kV-230008 | 230008 | 59 | Aug-20 | Nov-20 | Jan-21 | $700,150 |
| Transmission Upgrades-138/230 kV-230010 | 230010 | 2 | Sep-20 | Jan-21 | Jan-21 | $900 |
| Transmission Upgrades-138/230 kV-230038 | 230038 | 1 | Oct-20 | Jan-21 | Jan-21 | $450 |
| Transmission Upgrades-138/230 kV-230003 | 230003 | 35 | Oct-20 | Jan-21 | Feb-21 | $15,750 |
| Transmission Upgrades-138/230 kV-230005 | 230005 | 24 | Oct-20 | Feb-21 | Feb-21 | $10,800 |
| Transmission Upgrades-138/230 kV-230004 | 230004 | 40 | Nov-20 | Feb-21 | Mar-21 | $18,000 |
| Transmission Upgrades-138/230 kV-230625 | 230625 | 12 | Nov-20 | Mar-21 | Mar-21 | $5,400 |
| Transmission Upgrades-138/230 kV-230021 | 230021 | 17 | Nov-20 | Mar-21 | Apr-21 | $7,650 |
| Transmission Upgrades-138/230 kV-230052 | 230052 | 9 | Dec-20 | Apr-21 | Apr-21 | $2,700 |
| Transmission Upgrades-69 kV-66024 | 66024 | 25 | Dec-20 | Apr-21 | Apr-21 | $27,750 |
| Transmission Upgrades-138/230 kV-230608 | 230608 | 18 | Dec-20 | May-21 | May-21 | $7,200 |
| Transmission Upgrades-138/230 kV-230603 | 230603 | 13 | Dec-20 | May-21 | May-21 | $1,800 |

The North American Electric Reliability Corporation ("NERC") defines the transmission system as lines operated at relatively high voltages varying from 69kV up to 765kV and capable of delivery large quantities of electricity. Tampa Electric's transmission system is made up of 69kV, 138kV and 230kV voltages and is designed to transmit power to the end-user 13.2kV distribution substations. As such, Tampa Electric does not attribute customer counts directly to individual transmission lines. It should be noted, that without Tampa Electric's transmission network in place, power could not be delivered to the distribution network which would result in automatic load loss.

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**Tampa Electric's Distribution Overhead Feeder Hardening - Year 2020 Details**

| Project ID | Circuit No. | Specific Project Detail | Customers | | | | Priority Customers | Project Start Month | Construction | | Project Cost in 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Residential | Small C&I | Large C&I | Total | | | Start Month | End Month | |
| Distribution Feeder Hardening-Breaker-60067752 | 13308 | Tampa Electric will install (6) new reclosers, replace (3) existing manual switches with (3) reclosers, (45) fuses, (27) trip savers, and upgrade (52) feeder poles | 1,220 | 260 | 36 | 1,516 | 26 | May-20 | Aug-20 | Dec-20 | $1,153,700 |
| Distribution Feeder Hardening-Breaker-60095496-Recloser-92203202 | 13807 | Tampa Electric will install (8) new reclosers,(194) fuses, (40) trip savers, and upgrade (86) feeder poles | 1,159 | 103 | 16 | 1,278 | 12 | May-20 | Aug-20 | Dec-20 | $1,679,500 |
| Distribution Feeder Hardening-Breaker-60315127-Recloser-92189137 | 13805 | Tampa Electric will install (4) new reclosers, (202) fuses, (37) trip savers, and upgrade (93) feeder poles | 356 | 61 | 4 | 421 | 0 | May-20 | Aug-20 | Dec-20 | $1,565,900 |
| Distribution Feeder Hardening-Breaker-60066445 | 13745 | Tampa Electric will install (11) reclosers, (38) fuses, (10) trip savers, and upgrade (31) feeder poles | 3,106 | 242 | 50 | 3,398 | 62 | May-20 | Aug-20 | Dec-20 | $833,150 |
| Distribution Feeder Hardening-Breaker-60064337 | 13533 | Tampa Electric will install (13) reclosers, (42) fuses, (5) trip savers, upgraded breaker relays, and upgrade (33) feeder poles | 2,161 | 235 | 36 | 2,432 | 34 | May-20 | Aug-20 | Dec-20 | $1,044,300 |

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TAMPA ELECTRIC
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200067-EI

# TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

JOHN H. WEBSTER

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**FILED: APRIL 10, 2020**

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**JOHN H. WEBSTER**

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**INTRODUCTION:**

**Q.** Please state your name, address, occupation and employer.

**A.** My name is John H. Webster. My business address is 2200 East Sligh Av, Tampa, Florida 33610. I am employed by Tampa Electric Company ("Tampa Electric" or "the Company") as the Line Clearance Arborist Lead, Line Clearance and Construction Services, Energy Delivery Department.

**Q.** Please describe your duties and responsibilities in that position?

**A.** My duties and responsibilities include ensuring safe, efficient, and cost-effective methods are in place for all line clearance activities associated with the construction and maintenance of Tampa Electric's transmission and distribution systems. This includes responsibility for line clearance contracted personnel, assigned budgets, equipment, and implementation of proper line clearance methodology. As it relates to this filing, I am responsible for the safe, timely, and efficient implementation of the company's Vegetation Management Program and Transmission Access Program.

**Q.** Please describe your educational background and professional experience?

**A.** I received a Bachelor of Science degree in forestry from the University of Kentucky in 2003 and became an International Society of Arboriculture certified arborist in 2003 and an International Society of Arboriculture certified utility specialist in 2004. I have been with Tampa Electric for fourteen years, and held positions as a Line Clearance Supervisor, Line Clearance Arborist, and Line Clearance Arborist Lead.

**Q.** What is the purpose of your testimony in this proceeding?

**A.** The purpose of my direct testimony is to present the Vegetation Management and Transmission Access Storm Protection Programs in Tampa Electric's 2020-2029 Storm Protection Plan. My testimony will explain how the company's Vegetation Management Program complies with Rule 25-6.030(3)(f), and how the Transmission Access Program complies with Rule 25-6.030(3)(d)-(e). I will provide a description of the proposed Vegetation Management ("VM") Program and the Transmission Access Program. I will explain in detail the systematic approach the company used to develop the Vegetation

Management Program and the Transmission Access Program to ensure the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability are achieved.

**Q.** Are you sponsoring any exhibits in this proceeding?

**A.** No.

**TAMPA ELECTRIC'S SERVICE AREA**

**Q.** How many circuit miles of overhead distribution and transmission lines does Tampa Electric have?

**A.** The company has approximately 6,250 circuit miles of overhead distribution facilities and 1,350 circuit miles of overhead transmission facilities over the five counties Tampa Electric serves.

**Q.** Are there any parts of Tampa Electric's service area that were prioritized for enhancement, or any areas where enhancement would not be feasible, reasonable or practical, under the Vegetation Management and Transmission Access Programs?

**A.** No. The company did not exclude any area of the company's existing transmission and distribution facilities for enhancement under these programs due to feasibility, reasonableness, or practicality.

**TAMPA ELECTRIC'S CURRENT VEGETATION MANAGEMENT PROGRAM**

**Q.** What are the components of the proposed Vegetation Management Program in the company's SPP?

**A.** The company's VM Program consists of four parts including existing legacy storm hardening VM activities and three new VM initiatives. The company's existing VM activities and the three new VM initiatives are described below.

**Q.** Please explain Tampa Electric's current distribution and transmission vegetation management cycles.

**A.** Tampa Electric's current Vegetation Management Program ("VMP") calls for trimming the company's distribution system on a four-year cycle. The company's bulk transmission lines of 138kV and 230kV are maintained on a two-year cycle and 69kV lines are maintained on a three-year cycle.

**Q.** When did Tampa Electric begin a four-year trim cycle for its distribution system?

**A.** The company received approval from the Commission in Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI, issued June 12, 2012 to convert from a three-year trim cycle to a four-year trim cycle. This approved trim cycle change gave Tampa Electric flexibility to change circuit prioritization using the company's reliability-based methodology.

**Q.** Approximately how many miles of distribution lines does Tampa Electric trim per year as part of this four-year cycle?

**A.** Tampa Electric's current four-year trim cycle calls for trimming approximately 1,560 distribution miles annually.

**Q.** Describe Tampa Electric's transmission VM cycle.

**A.** As I mentioned previously, the company's bulk transmission lines of 138kV and 230kV are maintained on a two-year cycle and 69kV lines are maintained on a three-year cycle. Transmission circuits are managed on a 'strict' or 'hard' cycle. Although strict, the schedule allows adequate flexibility to accommodate new or redesigned circuits. All circuits above 200kV are managed in accordance with Federal Energy Regulatory Commission ("FERC") standard FAC-003-4.

**Q.** Approximately how many miles of transmission lines does Tampa Electric trim per year as a part of these cycles?

**A.** Tampa Electric's current transmission cycle calls for trimming approximately 530 total transmission miles annually, 255 non-bulk miles and 275 bulk miles.

**Q.** Would you explain the company's reliability-based methodology?

**A.** Tampa Electric's System Reliability and Line Clearance Departments use a third-party vegetation management software application to develop a multi-year VMP which optimizes activities from both a reliability-based and cost-effectiveness standpoint. This approach allows the company to model circuit behavior and schedule trimming at the optimal time.

**Q.** Please describe the company's current VM specifications.

**A.** Tampa Electric uses a contract workforce of approximately 220 tree trim personnel throughout the company's distribution and transmission system. Vegetation to conductor clearance for distribution primary facilities is ten feet, and vegetation to conductor clearances for transmission varies from fifteen feet to thirty feet, depending on voltage. All Tampa Electric contractors are required to follow American National Standards Institute ("ANSI") A300 pruning guidelines.

**Q.** What are ANSI pruning guidelines?

**A.** The American National Standards Institute or ANSI uses industry research to generate a set of guidelines for a variety of industry practices. The ANSI A-300 guidelines help arborists determine the manner in which vegetation should be trimmed to achieve desired objectives all while preserving tree health and structure. The Z-133 guidelines help arborists and non-arborists follow safe work practices.

**Incremental Vegetation Management Initiatives**

**Q.** In his direct testimony, Gerard R. Chasse mentions that Tampa Electric used a consultant to analyze potential incremental vegetation management activities. Please explain why Tampa Electric used this consultant.

**A.** The company used Accenture for its industry knowledge and data analysis expertise. Additionally, Accenture has worked with Tampa Electric on a number of VM analyses in the past, owns the software application, and has a working knowledge of the company's VM processes.

**Q.** How did Accenture analyze Tampa Electric's existing VM activities?

**A.** Accenture analyzed Tampa Electric's historical reliability and VM data and incorporated (FEMA HAZUS) wind speed and storm probability data to model the costs and benefits of various VM activities. Accenture collected thirteen years of reliability and VM data. The reliability data included outages related to vegetation as well as a percentage of other outages that may have a vegetation component such as weather cause codes and unknown cause codes. The VM data included circuit-specific trim dates and costs. The VM software application was the primary tool for analysis.

**Q.** How does Accenture's VM software application work?

**A.** The VM software application uses multi-year outage data and pairs it with multi-year VM activity and cost to generate reliability and cost 'curves.' These curves model circuit behavior and recommend the optimal time for VM. The application also has a corrective trimming and storm function that allows it to estimate costs associated with corrective or mid-cycle trimming and storm restoration.

**Q.** Did Accenture update the tree trimming model for this study?

**A.** Yes. Tampa Electric worked with Accenture to update the software application with the company's most recent outage and cost data. Accenture further updated the application by creating an enhanced storm module to accompany the existing storm module already in the application. The enhanced storm module allowed the application to perform analyses on partial circuits and entire circuits.

**Q.** Did Accenture analyze multiple scenarios involving potential incremental VM activities?

**A.** Yes, Accenture looked at multiple mileage scenarios to determine the costs of incremental VM activities and the benefits associated with extreme weather events and overall service reliability. Accenture modeled seven scenarios ranging from zero incremental VM miles to nine-hundred incremental VM miles. The addition of the enhanced storm module allowed Accenture to analyze the costs and benefits of two mid-cycle VM scenarios.

**Q.** What were Accenture's conclusions?

**A.** Accenture concluded a supplemental VM initiative consisting of seven hundred incremental miles would provide a twenty-one percent improvement in the company's storm restoration times and costs. Based on Accenture's work, the proposed mid-cycle VM initiative, consisting of four-hundred forty incremental miles inspected, would net an additional five percent improvement in the company's storm restoration times and costs.

**Q.** Did Accenture determine which combination of incremental activities provided the greatest level of benefit for the cost?

**A.** Yes. Accenture determined which combination of incremental activities provided the greatest benefit through the analysis and worked closely with company subject-matter experts to produce an operational plan that incorporates efficient, cost-effective contractor uptake. The result was a phased-in approach of four-hundred, five-hundred, seven-hundred miles scheduled for the first three years of the Storm Protection Plan.

**Q.** Did Accenture analyze potential incremental transmission VM activities?

**A.** No, Accenture did not analyze the incremental transmission activities primarily because the VM software application is designed for distribution circuits. Additionally, much of the company’s transmission VM plan is regulated by FERC standard FAC-003-4.

**Q.** Did Tampa Electric determine that it should perform any incremental transmission vegetation management?

**A.** Yes, the company assessed its transmission circuits and found through operational experience and storm “lessons learned” that approximately ten percent of the 69kV transmission miles were particularly difficult and expensive to maintain, largely inaccessible, and prone to hazard trees. The company’s proposed 69kV reclamation project would essentially remove the vegetative obstructions and minimize outages related to hazard tree fall-ins.

**Q.** Can you please describe each of the incremental VM activities, both for transmission and distribution, that Tampa Electric proposes as elements of its 2020-2029 Storm Protection Plan?

**A.** In addition to its existing VM activities, Tampa Electric is proposing three initiatives (two distribution and one transmission) designed to further harden the company's electrical infrastructure against extreme weather events and improve overall system reliability. They are the Supplemental Distribution Circuit VM Initiative, the Mid-Cycle Distribution VM Initiative and 69 kV Transmission VM Reclamation Initiative.

The Supplemental Distribution Circuit VM Initiative will increase the volume of full circuit VM performed on an annual basis. The Mid-cycle Distribution VM Initiative is an inspection-driven, site-specific approach designed to target vegetation that cannot be effectively maintained by cycle trimming. This initiative will also target hazard trees. The 69 kV Transmission VM

Reclamation Initiative is designed to remove obstructing vegetation and hazard trees from specific sites along the company's 69 kV transmission system.

**Q.** Please explain how Tampa Electric's Incremental Vegetation Management Initiatives will enhance the utility's existing transmission and distribution facilities?

**A.** The Supplemental Distribution Circuit VM Initiative, once fully implemented, is expected to provide a sixteen percent and twenty-one percent improvement in the company's day-to-day and storm restoration times and costs, respectively. The Mid-Cycle Distribution VM Initiative is expected to net an additional two percent and five percent improvement in the company's day-to-day and storm restoration times and costs, respectively. The hazard tree removal portion of the initiative will add further benefit to storm outage prevention. The 69 kV Transmission VM Reclamation Initiative will benefit storm outage prevention by improving vegetation to conductor clearance and reducing hazard tree potential. During extreme weather events, these initiatives will have added benefit for faster outage detection, more accurate damage assessment, and lower restoration times and costs.

**Q.** How many incremental miles of distribution and transmission overhead facilities does Tampa Electric plan to trim over the first three years of the Plan?

**A.** For the first three years, the company plans to trim approximately 1,600 additional miles of distribution lines and an additional 56 miles of 69 kV transmission lines. The number of miles of mid-cycle trimming and removal will be determined by the inspection findings; however, the company plans to inspect 439 miles in the first three years of the SPP.

**Q.** What is the total number of miles, including both baseline and incremental trimming, that Tampa Electric plans to trim over the first three years of the Plan?

**A.** The company plans to trim approximately 4,680 miles of distribution facilities under the baseline cycle and 1,600 miles under the Supplemental Trimming Initiative for a total of approximately 6,280 miles of distribution trimming. The company also plans to inspect an additional 439 miles of distribution facilities under the Mid-Cycle Initiative. The company plans to trim approximately 1,590 miles of transmission facilities under the baseline cycle, plus an additional 83 miles under the 69kV Reclamation Initiative, for a total of approximately 1,673 miles of transmission facility trimming.

**Q.** What are the estimated annual labor and equipment costs for the VM Program during the first three years of the SPP?

**A.** The estimated annual labor and equipment costs for the first three years of the SPP total $67.2M, commencing second quarter of 2020. The four-year distribution cycle labor and equipment costs for the first three years are $36.8M, and the incremental distribution VM labor and equipment costs are $20.6M. The first three years of transmission cycle(s) labor and equipment costs are $8.3M, and the incremental transmission VM labor and equipment costs are $1.5M. The total cost for the Program is set out in Section 7 of the company’s 2020-2029 SPP.

**Q.** Did Tampa Electric prepare an analysis of the estimated costs and benefits of the Program?

**A.** Yes, pursuant to Rule 25-6.030(3)(i), the company explored incremental VM strategies for the express purposes of protecting its electrical infrastructure against extreme weather events and reducing restoration times and costs. The company further acquired the assistance of Accenture, an outside consultant with expertise in data analysis and utility VM, to help with the analysis. Based on the data available and the analysis performed, Tampa Electric believes that the twenty-six percent improvement in storm restoration time and cost are worth the $10.7M annual average increase in distribution VM operations and maintenance expenses. The benefits associated with reduced restoration time and cost and lessened vegetation contact potential also clearly show that the $2.2M 69kV reclamation project additional annual expense is a tremendous value for Tampa Electric customers.

**TRANSMISSION ACCESS PROGRAM**

**Q.** Please describe the Transmission Access Program?

**A.** Tampa Electric's Transmission Access Program is designed to ensure the company always has access to its transmission facilities so it can promptly restore its transmission system when outages occur. Increased power demands and changes in topography and hydrology related to customer development, along with several years of active storm seasons, have negatively impacted the company’s access to its transmission infrastructure. The company’s proposed Transmission Access Program involves repairing and restoring transmission access by constructing access roads and access bridges to critical routes throughout the company’s transmission corridors. The program is expected to start projects in 2021 and complete the program by 2030.

**Q.** Please explain how Tampa Electric’s Transmission Access Program will enhance the utility’s existing transmission facilities.

**A.** This program will enhance the existing transmission facilities by improving the company’s access to its critical transmission circuits, especially during ‘wet’ and storm seasons, which will promote system resiliency and timelier storm restoration.

**Q.** In the direct testimony of Gerard R. Chasse, he mentions that Tampa Electric used a consultant to assist with the development of the Transmission Access Program. Please explain why Tampa Electric used a consultant to develop the Transmission Access Program.

**A.** Tampa Electric hired 1898 & Co, a consultant with expertise in the areas of T&D system hardening and cost-benefit analysis. 1898 was selected for its industry knowledge and data analysis expertise. 1898 & Co. was engaged to analyze the cost-benefits of the access projects for prioritization within the Program as well as the overall Plan. Jason D. De Stigter from 1898 will provide direct testimony to more fully detail the approach taken for each of the Programs they supported, including Transmission Access.

**Q.** Please explain how Tampa Electric and 1898 & Co. prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Transmission Access Program?

**A.** The methodology used to develop the estimate of the reduction in outage times and restoration costs is addressed in detail in Jason D. De Stigter’s direct testimony, but in general, 1898 developed a model that calculates the benefit in terms of decreased restoration cost and reduced Customer Minutes of Interruption (“CMI”) for each proposed Transmission Access Project.

**Q.** Did Tampa Electric prepare an analysis of the estimated costs and benefits of the Transmission Access Program?

**A.** Yes. A table comparing the estimated costs and benefits of this Program is included below.

| Tampa Electric - Proposed 2020-2029 Storm Protection Plan<br>Transmission Access Enhancements Program<br>Projected Costs versus Benefits | | | | | | |
|---|---|---|---|---|---|---|
| **Storm Protection Program** | **Projected Costs (in Millions)** | | **Projected Reduction in Restoration Costs (Approximate Benefits in Percent)** | **Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent)** | **Program Start Date** | **Program End Date** |
| | **Capital** | **O&M** | | | | |
| **Transmission Access Enhancements** | $14.8 | $0.0 | 10 | 74 | Q1 2021 | After 2029 |

**Q.** Please explain the methodology Tampa Electric used in prioritizing the Projects the company is including in the Transmission Access Program.

**A.** The methodology used to develop the prioritization of Projects in these Programs is addressed in detail in Jason D. De Stigter’s direct testimony. In general, the company and 1898 developed a potential cost estimate and estimated benefits for each potential Project in the Program. These estimated benefits included both reduced customer minutes of interruption and reduced restoration costs. These benefits were then combined and a cost benefit NPV was calculated for each potential Project. The NPVs were then used to rank or prioritize each Project within a given SPP Program. The rankings will serve as a guide, but the company will also apply operational experience and judgment when selecting Projects.

**Q.** Did Tampa Electric prepare a list of transmission access projects that the company is planning to begin in 2020, including their associated starting and projected completion dates?

**A.** No, the company did not prepare a list of Transmission Access Projects for 2020. Tampa Electric plans to use 2020 to select engineering and construction vendors and coordinate the necessary environmental permitting.

**Q.** Did Tampa Electric prepare an estimated number of Transmission Access projects it plans on initiating in 2021 and 2022?

**A.** Yes, using the analysis provided by 1898, the company prioritized a list of fourteen Projects it plans to begin in 2021 and 2022.

**Q.** Did Tampa Electric prepare an estimate of the costs for the projects planned for 2021 and 2022?

**A.** Yes, the company plans to spend $2.9M for Projects planned in 2021 and 2022. The table below sets out the total number of Projects and the estimated costs for the first three years of the Plan.

| | Tampa Electric's Transmission Access Enhancements Program Projects by Year and Projected Costs (in millions) | |
|---|---|---|
| | Projects | Costs |
| 2020 | 0 | $0.0 |
| 2021 | 8 | $1.4 |
| 2022 | 6 | $1.5 |

**Q.** Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

**A.** Yes, the company used recent road and bridge actuals to prepare estimates for the permitting, surveying, engineering, and construction costs. The total capital cost estimate for the Transmission Access Enhancement Program is $14.8M. The are no operating costs associated with the Projects. The table below sets out the estimated costs for the Program by year over the ten-year plan horizon.

| | Total Transmission Access Enhancements Program Costs (in thousands) | | |
|---|---|---|---|
| | **Access Road Projects Costs** | **Access Bridge Project Costs** | **Total Transmission Access Project Costs** |
| **2020** | $0 | $0 | $0 |
| **2021** | $604 | $780 | $1,383 |
| **2022** | $391 | $1,118 | $1,509 |
| **2023** | $0 | $1,606 | $1,606 |
| **2024** | $810 | $853 | $1,663 |
| **2025** | $978 | $360 | $1,338 |
| **2026** | $0 | $354 | $354 |
| **2027** | $3,325 | $0 | $3,325 |
| **2028** | $1,982 | $0 | $1,982 |
| **2029** | $1,065 | $601 | $1,667 |

**CONCLUSIONS:**

**Q.** Please summarize your direct testimony.

**A.** My testimony and my accompanying exhibits present and support the Incremental Vegetation Management Program within Tampa Electric's proposed 2020-2029 Storm Protection Plan. This Plan was developed consistent with the requirements of Section 366.96, Florida Statutes and the implementing Rule 25-6.030, F.A.C., adopted by the Commission.

**Q.** Should Tampa Electric's proposed Vegetation Management and Transmission Access Programs be approved?

**A.** Yes. Tampa Electric's proposed 2020-2029 Vegetation Management and Transmission Access Programs should be approved. These Programs are designed to reduce restoration costs, reduce outage times, improve overall reliability and increase customer satisfaction in a cost-efficient manner.

**Q.** Does this conclude your testimony?

**A.** Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200067-EI

# TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

A. SLOAN LEWIS

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**FILED: APRIL 10, 2020**

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**A. SLOAN LEWIS**

**INTRODUCTION:**

**Q.** Please state your name, address, occupation and employer.

**A.** My name is A. Sloan Lewis. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the Company") in the Finance Department as Director, Regulatory Accounting.

**Q.** Please describe your duties and responsibilities in that position.

**A.** My duties and responsibilities include the accounting oversight of all cost recovery clauses and riders for Tampa Electric and Peoples Gas, the settlement of all fuel and power transactions for Tampa Electric and Peoples Gas System and the accounts payable department for Tampa Electric, Peoples Gas System and New Mexico Gas Company.

**Q.** Please describe your educational background and professional experience.

**A.** I received a Bachelor of Science degree in accounting from Florida State University in 1994 and a Master of Education from the University of North Florida in 1996. I joined Tampa Electric in 2000 as a Fuels Accountant and over the past 19 years have expanded my cost recovery clause responsibilities. Then in 2015, I was promoted to Manager, Regulatory Accounting with responsibilities for all the recovery clauses and riders for Tampa Electric and Peoples Gas System. I was promoted to my current role as Director, Regulatory Accounting in 2017.

**Q.** What is the purpose of your testimony in this proceeding?

**A.** The purpose of my testimony in this proceeding is to demonstrate that the company’s 2020-2029 Storm Protection Plan complies with Rule 25-6.030(g)-(h), Florida Administrative Code, *i.e.*, the Storm Protection Plan (“SPP”) rule. Section 3(g) requires a utility to provide an estimate of the annual jurisdictional revenue requirements for each year of its SPP. Section 3(h) requires a utility to provide an estimate of rate impacts for each of the first three years of the SPP for the utility’s typical residential, commercial, and industrial customers. My testimony also explains the methodology used to calculate these estimates.

**Q.** Have you prepared an exhibit to accompany your direct testimony?

**A.** Yes. Exhibit No. ASL-1, entitled "Tampa Electric's 2020-2029 SPP Total Revenue Requirements by Program" was prepared under my direction and supervision. This Exhibit shows the Annual Revenue Requirement for the company's 2020-2029 SPP Programs.

**CALCULATION OF THE ESTIMATED ANNUAL JURISDICTIONAL REVENUE REQUIREMENTS FOR TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION PLAN**

**Q.** What is the estimated annual jurisdictional revenue requirements for each year of the company's proposed SPP?

**A.** The estimated annual jurisdictional revenue requirements for each year of the SPP are included in the table below. The revenue requirements of each SPP are set out in my Exhibit No. ASL-1.

Total SPP Revenue Requirement (2020-2029)

| YEAR | Revenue Requirements |
|---|---|
| 2020 | $24,428,727 |
| 2021 | $36,739,224 |
| 2022 | $52,213,995 |
| 2023 | $71,458,756 |
| 2024 | $86,932,411 |
| 2025 | $105,253,007 |
| 2026 | $122,774,696 |
| 2027 | $139,916,133 |
| 2028 | $157,595,194 |
| 2029 | $174,852,375 |

**Q.** How were the estimated annual jurisdictional revenue requirements for the proposed plan developed?

**A.** The estimated annual jurisdictional revenue requirements were developed with cost estimates for each of the SPP Programs plus depreciation and return on SPP assets, as outlined in Rule 25-6.031(6), F.A.C., the Storm Protection Plan Cost Recovery Clause ("SPPCRC") Rule.

**Q.** Do these revenue requirements include any costs that are currently recovered in base rates?

**A.** Yes. As described further below, the revenue requirement amounts shown above reflect all of the investments and expenses associated with the activities in the Plan without regard to whether some of those costs may currently be subject to recovery through the company's existing base rates and charges. For illustrative purposes, the company calculated the 2017 to 2019 three-year actual amounts of certain operations and maintenance expenses associated with its current Storm Hardening Plan to be approximately $12.9 million. Since these Storm Hardening Plan activities are proposed to be part of the company's SPP and are not "new" or "incremental" storm protection activities, this $12.9 million amount can be viewed as a reasonable proxy for the amount of Storm Protection Plan costs currently being recovered by the company through its base rates and charges. Of course, whether and the extent to which the investments and costs associated with the company's SPP will be recovered through the SPPCRC or continue to be recovered through base rates will be addressed in Docket No. 20200092-EI, the SPPCRC Docket.

**Q.** Do the estimated annual jurisdictional revenue requirements include the annual depreciation expense on SPP capital expenditures?

**A.** Yes. Rule 25-6.031 states that the annual depreciation expense is a cost that may be recovered through the SPPCRC. As a result, the estimated annual jurisdictional revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures, *i.e.*, those initiated after April 10, 2020, using the depreciation rates from Tampa Electric’s most current Depreciation Study, approved in PSC-12-0175-PAA-EI.

**Q.** Was the depreciation savings on the retirement of assets removed from service during the SPP capital projects considered in the development of the revenue requirement?

**A.** Yes. In the development of the revenue requirements, depreciation expense from the SPP capital asset additions has been reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the SPP capital projects.

**Q.** Do the estimated annual jurisdictional revenue requirements include a return on the undepreciated balance of the SPP assets?

**A.** Yes. Rule 25-6.031 6(c) states that the utility may recover a return on the undepreciated balance of the asset costs through the SPPCRC. As a result, this return was included in the estimated annual jurisdictional revenue requirement. In accordance with the FPSC Order No. PSC-12-0425-PAA-EU, from the 2012 Stipulation and Settlement agreement, Tampa Electric calculated a return on the undepreciated balance of the asset costs at a weighted average cost of capital using the return on equity from the May 2019 Actual Surveillance Report.

**Q.** In the development of the estimated annual jurisdictional revenue requirements did the company consider SPP capital expenditures prior to the plan filing date in the depreciation and return on asset calculations?

**A.** No. Only capital expenditures for SPP Projects to be initiated after April 10, 2020 were included in the depreciation and return on asset calculations included in the estimated annual jurisdictional revenue requirements.

**Q.** In the calculation of the estimated annual jurisdictional revenue requirements did the company include Allowance for Funds Used During Construction (“AFUDC”)?

**A.** No. Per Rule 25-6.0141, F.A.C, in order for projects to be eligible for AFUDC, they must involve "gross additions to plant in excess of 0.5 percent of the sum of the total balance in Account 101, Electric Plant in Service, and Account 106, Completed Construction not Classified, at the time the project commences and are expected to be completed in excess of one year after commencement of construction." None of the projects proposed in Tampa Electric's 2020-2029 SPP meet the criteria for AFUDC eligibility.

**Q.** Does Tampa Electric intend to seek recovery of the estimated SPP costs through the SPPCRC, in accordance with FAC rule 26-6.031?

**A.** Yes, Tampa Electric will be filing for cost recovery of the estimated SPP costs through the SPPCRC. However, as mentioned above, the extent to which the investments and costs associated with the company's SPP will be recovered through the SPPCRC or continue to be recovered through base rates will be addressed in Docket No. 20200092-EI.

**CALCULATION OF THE ESTIMATED RATE IMPACTS FOR YEARS 2020-2023 OF THE STORM PROTECTION PLAN**

**Q.** Please provide an estimate of rate impacts for each of the first three years of the proposed SPP for typical Tampa Electric residential, commercial, and industrial customers.

**A.** Tampa Electric prepared estimated rate impacts of the SPP for 2020, 2021, 2022 and 2023. While there are not going to be any billed rate impacts during 2020, the 2020 costs have been calculated separately from the 2021 costs so the impact of each year on the 2021 rate impacts is clear. This is because the 2020 costs will be recovered at the same time as the 2021 costs through clause rates initiating in January 2021. The estimated rate impacts for each of the first three years of the proposed SPP for a typical residential, commercial, and industrial Tampa Electric customer are listed in the table below.

| | Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent) | | | |
|---|---|---|---|---|
| | Customer Class | | | |
| | Residential 1000 kWh | Residential 1250 kWh | Commercial 1 MW 60 percent Load Factor | Industrial 10 MW 60 percent Load Factor |
| 2020 | 1.50 | 1.48 | 1.44 | 0.55 |
| 2021 | 2.22 | 2.21 | 2.14 | 0.84 |
| 2022 | 3.09 | 3.06 | 2.98 | 1.13 |
| 2023 | 4.12 | 4.07 | 3.95 | 1.46 |

**Q.** How were the estimated rate impacts for each of the first three years of the proposed SPP for a typical residential and commercial/industrial customer determined?

**A.** For each year, the Programs were itemized and identified as either substation, transmission, or distribution costs. Each of those functionalized costs was then allocated to rate class using the allocation factors for that function. The allocation factors were from the Tampa Electric 2013 Cost of Service Study prepared in Docket No. 20130040-EI, which was used for the company's current (non-SoBRA) base rate design. Once the total SPP revenue requirement recovery allocation to the rate classes was derived, the rates were determined in the same manner. For Residential, the charge is a kWh charge. For both Commercial and Industrial, the charge is a kW charge. The charges are derived by dividing the rate class allocated SPP revenue requirements by the 2020 energy billing determinants (for residential) and by the 2020 demand billing determinants (for commercial and industrial). Those charges were then applied to the billing determinants associated with typical bills for each group to calculate the impact on those bills. This was done using a combination of 2020 and 2021 costs for the 2021 bills, and for each year 2022 and 2023 for those bills.

**Q.** When will the company file its petition for the establishment of the 2021 SPPCRC rates for Tampa Electric's SPP'S costs?

**A.** The company plans to file the SPPCRC petition for 2021 rates on the schedule specified in applicable orders establishing procedure in Docket No. 20200092-EI.

**Q.** Will the rates established through the 2021 SPPCRC differ from those presented in the rate impact calculations in the SPP?

**A**. Yes. The rate impacts presented above reflect the "all-in" costs of the company's SPP without regard to whether the costs are or will be recovered through the SPPCRC or through the company's base rates and charges. The extent to which the investments and costs associated with the company's SPP will be recovered through the SPPCRC or continue to be recovered through base rates will be addressed in Docket No. 20200092-EI.

In addition, when it makes its SPPCRC filing, the company will use more recent billing determinants based on the most current load forecast.

The company will also take steps to prevent double recovery of any costs through both base rates and the clause.

**CONCLUSIONS**

**Q.** Please summarize your direct testimony.

**A.** My testimony and exhibit demonstrate that Tampa Electric's estimated annual jurisdictional revenue requirements for each of the 10 years of the SPP and rate impacts for each of the first 3 years of the SPP for the utility's typical residential, commercial, and industrial customers comply with Rule 25-6.030(3)(g)-(h). These calculations were performed in accordance with the requirements of Section 366.96, Florida Statutes and the implementing Rule 25-6.030, F.A.C., adopted by the Commission.

**Q.** Does this conclude your testimony?

**A.** Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 2020067-EI
WITNESS: LEWIS

# EXHIBIT

# OF

# A. SLOAN LEWIS

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**EXHIBIT NO. ASL-1**
**WITNESS: LEWIS**
**PAGE 1 OF 1**
**FILED: 04/10/2020**

| Tampa Electric's 2020-2029 Storm Protection Plan Total Revenue Requirements by Program (in Millions) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
| Distribution Lateral Undergrounding | $0.19 | $4.66 | $13.83 | $23.93 | $33.76 | $43.83 | $54.01 | $64.01 | $73.84 | $83.91 | $395.97 |
| Transmission Asset Upgrades | $0.14 | $1.25 | $2.69 | $4.16 | $5.45 | $6.82 | $8.45 | $9.91 | $11.40 | $12.66 | $62.93 |
| Substation Extreme Weather Protection | $0.00 | $0.00 | $0.00 | $0.00 | $0.28 | $0.95 | $1.42 | $1.93 | $2.47 | $2.82 | $9.87 |
| Distribution Overhead Feeder Hardening | $0.14 | $1.33 | $3.42 | $6.33 | $9.30 | $12.19 | $15.06 | $17.83 | $20.64 | $23.53 | $109.77 |
| Transmission Access Enhancements | $0.00 | $0.06 | $0.19 | $0.33 | $0.48 | $0.61 | $0.69 | $0.85 | $1.07 | $1.22 | $5.50 |
| Distribution Pole Replacements | $0.25 | $1.41 | $2.60 | $3.96 | $5.32 | $6.69 | $7.79 | $8.61 | $9.42 | $10.22 | $56.27 |
| **O&M** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **Total** |
| Distribution Vegetation Management - planned | $16.49 | $19.76 | $21.18 | $24.00 | $24.22 | $25.55 | $26.77 | $27.99 | $29.42 | $30.94 | $246.31 |
| Distribution Vegetation Management - unplanned | $1.30 | $1.30 | $1.20 | $1.10 | $1.10 | $1.10 | $1.20 | $1.20 | $1.30 | $1.30 | $12.10 |
| Transmission Vegetation Management - planned | $2.63 | $3.53 | $3.59 | $3.66 | $3.04 | $3.13 | $3.23 | $3.30 | $3.38 | $3.46 | $32.95 |
| Transmission Vegetation Management - unplanned | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Transmission Asset Upgrades | $0.11 | $0.30 | $0.30 | $0.33 | $0.24 | $0.38 | $0.36 | $0.33 | $0.39 | $0.24 | $2.98 |
| Distribution Overhead Feeder Hardening | $0.21 | $0.38 | $0.40 | $0.79 | $0.82 | $1.02 | $1.06 | $1.17 | $1.42 | $1.64 | $8.92 |
| Distribution Infrastructure Inspections | $0.71 | $1.00 | $1.02 | $1.04 | $1.06 | $1.08 | $1.10 | $1.13 | $1.15 | $1.17 | $10.46 |
| Transmission Infrastructure Inspections | $0.47 | $0.47 | $0.48 | $0.49 | $0.50 | $0.51 | $0.52 | $0.53 | $0.54 | $0.56 | $5.09 |
| SPP Planning & Common | $0.99 | $0.39 | $0.20 | $0.20 | $0.21 | $0.21 | $0.22 | $0.22 | $0.22 | $0.23 | $3.10 |
| Other Legacy Storm Hardening Plan Items | $0.28 | $0.28 | $0.29 | $0.29 | $0.30 | $0.30 | $0.31 | $0.32 | $0.32 | $0.33 | $3.01 |
| Distribution Pole Replacements | $0.52 | $0.62 | $0.81 | $0.83 | $0.86 | $0.88 | $0.59 | $0.60 | $0.61 | $0.62 | $6.93 |

**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

**DOCKET NO. 20200067-EI**

# TAMPA ELECTRIC's STORM PROTECTION PLAN

**VERIFIED DIRECT TESTIMONY**

**OF**

**JASON D. DE STIGTER**

**ON BEHALF OF**

**TAMPA ELECTRIC COMPANY**

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20200067-EI**
**FILED: APRIL 10, 2020**

# VERIFIED DIRECT TESTIMONY OF JASON D. DE STIGTER
# ON BEHALF OF
# TAMPA ELECTRIC COMPANY

## 1. INTRODUCTION

**Q1. Please state your name and business address.**

**A1.** My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

**Q2. By whom are you employed and in what capacity?**

**A2.** I am employed by 1898 & Co., and lead the Capital Asset Planning team as part of our Utility Consulting Practice. 1898 & Co. was established as the consulting and technology consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of over 200 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made up of more than 7,000 engineers, architects, construction professionals, scientists, consultants and entrepreneurs with more than 40 offices across the country and throughout the world.

**Q3. Briefly describe your educational background and certifications.**

**A3.** I received a Bachelor of Science Degree in Engineering and a Bachelor's in Business Administration from Dordt University. I am also a registered Professional Engineer in the state of Kansas.

**Q4. Please briefly describe your professional experience and duties at 1898 & Co.**

**A4.** I am a professional engineer with 13 years of experience providing consulting services to electric utilities. I have extensive experience in asset management, capital planning and optimization, risk and resilience assessments and analysis, asset failure analysis, and business case development for utility clients. I have been involved in numerous studies modeling risk for utility industry clients. These studies have included risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems. In my role as a project manager I have worked on and overseen risk and resilience analysis consulting studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resilience analysis models. My primary responsibilities are business development and project delivery within the Utility Consulting Practice with a focus on developing risk and resilience based business cases for large capital projects/programs.

Prior to joining 1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch inside their Asset Management Practice performing similar studies to the effort performed for Tampa Electric Company ("TEC").

**Q5. Have you previously testified before the Florida Public Service Commission or other state commissions?**

**A5.** I have not testified before the Florida Public Service Commission. I provided written, rebuttal, and oral testimony on behalf of Indianapolis Power & Light before the Indiana Utility Regulatory Commission and have supported many other regulatory filings. I have also testified in front of the Alaska Senate Resources Committee.

**Q6. What is the purpose of your direct testimony in this proceeding?**

**A6.** The purpose of my testimony is to summarize the results and methodology used by 1898 & Co. to develop a Storm Resilience Model with the following objectives:

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 overall investment level that maximizes customers benefit while not exceeding TEC technical execution constraints

Through my testimony I will describe the major elements of the Storm Resilience Model, which include a Major Storms Event Database, Storm Impact Model, Resilience Benefit Module, and Budget Optimization & Project Prioritization. Specifically, I will define resilience, review historical major storm event to impact TEC service territory, describe the datasets used in the Storm Impact Model and how they were used to model system impacts due to storms events, and explain how to understand the resilience benefit results. Throughout my testimony I will describe both how the assessment was performed and why it was performed as such. Finally, I will describe the calculations and results of the Storm Resilience Model.

**Q7. Are you sponsoring any attachments in support of your testimony?**

**A7.** Yes, I am sponsoring the 1898 & Co, Tampa Electric's Storm Protection Plan Resilience Benefits Report that is being included as Appendix F in Tampa Electric's 2020-2029 Storm Protection Plan.

**Q8. Were your testimony and the attachment identified above prepared or assembled by you or under your direction or supervision?**

**A8.** Yes.

**Q9. Are you also submitting workpapers?**

**A9.** No.

**Q10. What was the extent of your involvement in the preparation of the Storm Protection Plan?**

**A10.** I served as the 1898 & Co. project manager on the TEC Storm Protection Plan Assessments and Benefits Assessment. The evaluation utilized a Storm Resilience Model to calculate benefits. I worked directly with the TEC Team involved in the resilience-based planning approach. I was responsible for the overall project and was directly involved in the development of the Storm Resilience Model, the assessment and results, as well as being the main author of the report.

**2. RESILIENCE-BASED PLANNING OVERVIEW**

**Q11. Which of the Storm Protection Plan programs are evaluated within the Storm Resilience Model?**

**A11.** The Storm Resilience Model includes project benefits results, budget optimization, and project prioritization for the following Storm Protection Plan programs:

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening

- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

**Q12. How is resilience defined?**

**A12.** There are many definitions for resilience, I gravitate to the one used by the National Infrastructure Advisory Council (NIAC). Their definition of resilience is: "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."

This definition can be broken down into four phases of resilience described below with applicable definitions for the grid:

- **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)**

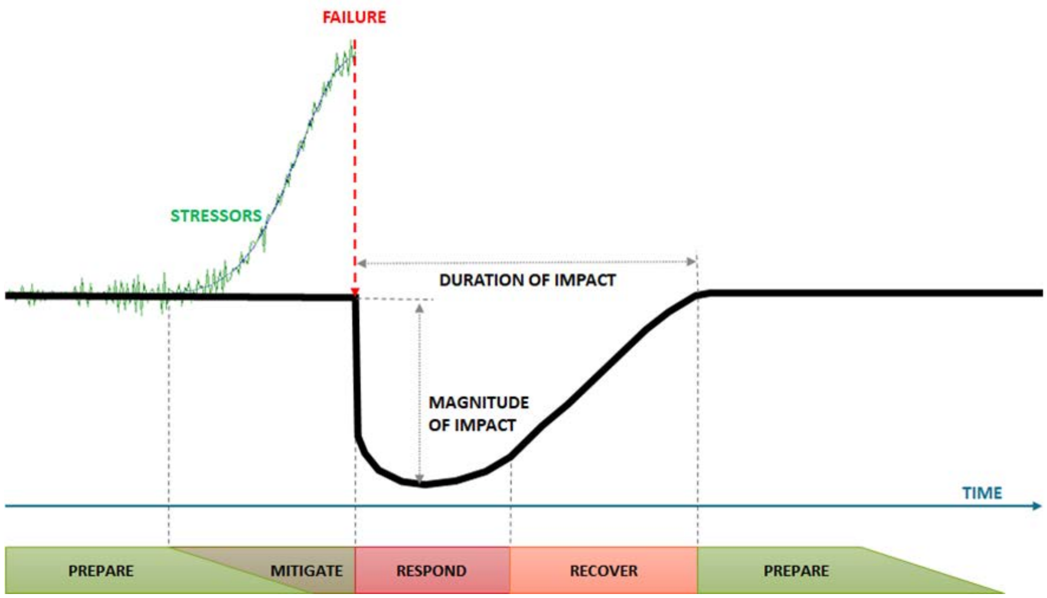
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).

- **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 1 below as a conceptual view of understanding resilience and how to mitigate the impact of events. 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 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 the system in terms of the magnitude of impact (vertical) and the duration (horizontal).

**Figure 1: Phases of Resilience**




**Q13. How does the Storm Resilience Model incorporate this definition?**

**A13.** The Storm Resilience Model utilizes a resilience-based planning approach to calculate hardening project benefits and prioritize projects. The model includes a 'universe' of major storm events as stressors on the TEC system. The database includes the probability of these events occurring as well as the magnitude of impact, in terms of the percentage of the sub-systems (e.g. substations, transmission lines, feeders, laterals), and duration to restore the system. The database also includes the restoration cost to return the system back to normal operation after each of the storm events.

The Storm Resilience Model also identifies, on a probability weighted basis, which specific portions of the TEC system would be impacted and their contribution to the overall restoration costs. The model also evaluates the storms impact for each portion of the system based on current status of the system and if that part of the system is hardened. For example, the Storm Resilience Model calculates magnitude and duration of a storm event on a distribution circuit given its current state and after it has been hardened.

**Q14. Please outline the type and count of hardening projects evaluated in the Storm Resilience Model.**

**A14.** Table 1 on the page below contains the list of potential hardening projects by program evaluated in the Storm Resilience Model.

**Table 1: Potential Hardening Project Count**

| 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 |

**Q15. How were these potential hardening projects identified?**

**A15.** The potential hardening projects were identified based on a combination of data driven assessments, field inspection of the system, and historical performance of TEC’s system during major storm events. The approach to identifying hardening projects employs asset management principles utilizing a bottom-up approach starting with the system assets. Additionally, hardening approaches for parts of the system were based on the balance of the resilience benefit they provide with the overall costs. I discuss this more below. Table 2 on the page below shows the asset types and counts included in the Storm Resilience Model used to develop hardening projects.

**Table 2: TEC Asset Base**

| 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 |

All of the assets that benefit from hardening are strategically grouped into potential hardening 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, those with a fuse or trip saver protection device, the preferred hardening approach is to underground the overhead circuits. The main cause of storm related outages, especially for weakened structures, is the wind blowing vegetation into conductor, causing structure failures. Therefore, 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 is still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than that of 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 provides 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 while 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. The non-wood materials have a 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 inspections 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.

**Q16. Why is this approach to hardening project identification important?**

**A16.** This approach to hardening project identification is important for several reasons.

1. The approach is comprehensive. As Table 2 shows, the approach evaluates nearly all the TEC's transmission and distribution (T&D) system. By considering and evaluating the entire system on a consistent basis, the results of the hardening plan provide confidence that portions of the TEC system are not overlooked for potential resilience benefit.
2. By breaking down the entire distribution system by protection zone, the resilience-based planning approach is foundationally customer centric. Each protection zone has a known number of customers and type of customers such as residential, small or large commercial and industrial, and priority customers. 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.

3. The granularity at the asset and project levels allows TEC to invest in portions of the system that provide the most value to customers from a restoration cost reduction, customers impacted (CI), and customer minutes interrupted (CMI) perspective. For example, a circuit may have 10 laterals, the Storm Resilience Model may determine that only 3 out of the 10 should be hardened. Without this granularity, hardening over investment is a concern. The adopted approach provides confidence that the overall plan is investing in parts of the system that provide the most value for customers.
4. The types of hardening projects include the mitigation measures over all the four phases of resilience providing a diverse investment plan. Since storm events cannot be fully eliminated, the diversification allows TEC to provide a higher level of system resilience.
5. The approach balances the use of robust data sets with TEC experience with storm events to develop storm hardening projects. Data-only approaches may provide decisions that don’t match reality, while

people-driven only solutions can be filled with bias. The approach balances the two to better identify types of hardening projects.

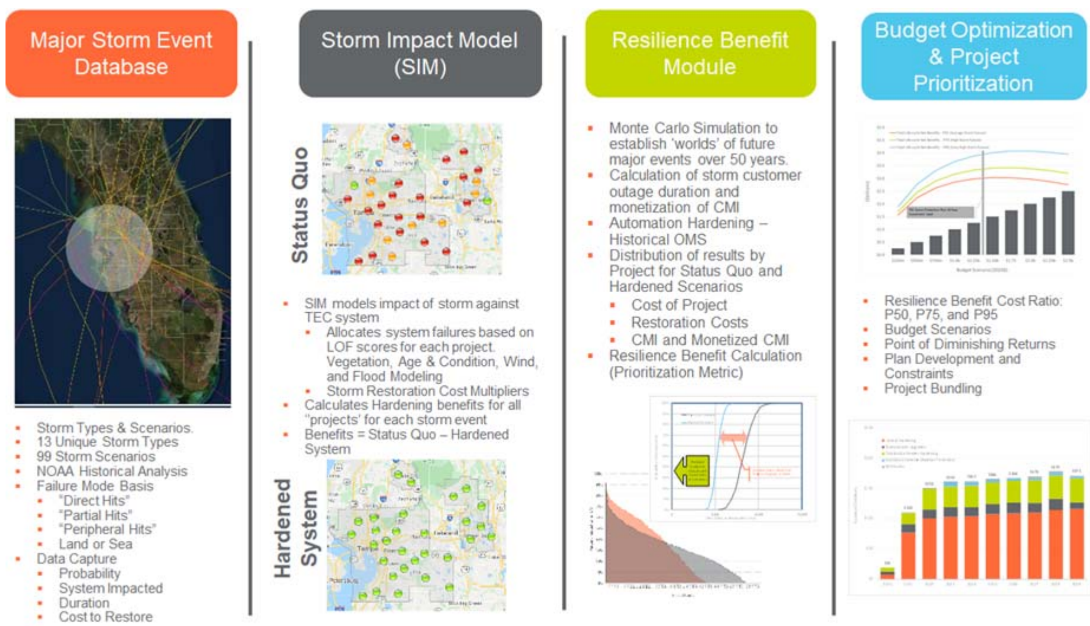
**Q17. Please describe the analysis 1898 & Co. conducted for TEC.**

**A17.** 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in the TEC T&D system utilizing a Storm Resilience Model. The Storm Resilience Model consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison across the system. The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, project, and program level. The results of the Storm Resilience Model are:

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

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit. Figure 2 provides an overview of the Storm Resilience Model used to calculate the project benefits and prioritize projects.

**Figure 2: Storm Resilience Model Overview**




The storms database includes the future 'universe' of potential storm events to impact the TEC service territory. 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.

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 wind zone the asset is in. Substation LOF is based on the SLOSH model results. The Storm Impact Model also estimates the restoration costs and CMI for each of the projects. 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 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 (i.e. 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, to randomly trigger the types storm events to impact the TEC service territory over the next 50 years. 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 Budget Optimization and Project Scheduling model prioritizes the projects based on the highest resilience benefit cost ratio. 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 realities (e.g. transmission outages) in scheduling the projects.

This resilience-based prioritization facilitates the identification of the critical 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 get the most value

**Q18. Why is it necessary to model storm hardening projects benefits using this resilience-based planning approach and Storm Resilience Model?**

**A18.** The Storm Resilience Model was architected and designed for the purpose of calculating storm hardening project benefit in terms of reduced restoration costs and customer minutes interrupted to build a Storm Protection Plan with the right level of investment that provides the most benefit for customer. It was necessary to model storm hardening projects using the resilience-based planning approach shown in Figure 2 for the following reasons:

1. The benefits of hardening projects are wholly dependent on the number, type, and overall impact of future storms to impact the TEC service territory. Different storms have dramatically different impact to TEC's system, for instance, in review of TEC's historical storm reports, it was observed that tropical storm events even 100 to 150 miles away from TEC's service territory from the Gulf side have greater impact in terms of restoration costs than larger storms 100 to 150 miles away on the Florida or Atlantic side. This is mainly caused by the energy that exists in the storm bands when they reach TEC's service territory. For this reason, the resilience-based planning approach includes the 'universe' of

potential major events that could impact TEC over the next 50 years, this is the Major Storms Event Database. In relation to the conceptual model showing the phases of resilience (Figure 1), I will discuss how the probabilities and system impacts of storm events were developed later in my testimony.

2. Major events cause assets to fail. Assets collectively serve customers. It only takes one asset failure to cause customer outages. The cost to restore the failed assets is dependent on the extent of the damage and resources used to fix the system. The duration to restore affected customers is dependent on the extent of the asset damage and the extent of the damage on the rest of the system. It may only take 4 hours to fix the failed equipment, but customers could be without service for 4 days if crews are busy fixing other parts of the system for 3 days and 20 hours. All of this is dependent on the type of storm to impact the system. Modeling this series of events, the phases of resilience from Figure 1, for the entire system at the asset and project level for both a Status Quo and Hardened scenarios is needed to accurately model hardening project benefits. Therefore, the

resilience-based planning approach includes the Storm Impact Model to calculate the phases of asset and project resilience for each of the 99 storm events for both scenarios. I discuss core data and calculations of the Storm Impact Model to develop the phases of resilience for every asset, project, program, and plan in further detail below in my testimony.

3. The output of the Storms Impact Model is the resilience benefit of each project for each of the 99 storm types. The life-cycle resilience benefit for each hardening project is dependent on the probability of each storm, and the mix of storm events to occur over the life of the hardening projects. A project's resilience value comes from mitigating outages and associated restoration costs not just for one storm event, but from several over the life-cycle of the assets. A future 'world' of major storm events could include a higher frequency of category 1 storms with average level impact and a low frequency of tropical storms with higher impacts. Alternatively, it could include a low frequency of category 1 type storms with high impact and a high frequency of tropical storms with lower impacts.

The number of storm combination scenarios is significant given there are 13 unique types of storm events. To model this range of combinations, the Storm Restoration Model employs stochastic modeling, or Monte Carlo Simulation, to randomly select from the 99 storm events to create a future 'world' of the 13 unique storm events to hit the TEC service territory. The Monte Carlo Simulation creates a 1,000-future storm 'worlds'. From this, the life-cycle resilience benefit of each hardening project can be calculated. This is done in the Resilience Benefit Module, I discuss this in more detail below in my Testimony.

4. To answer the questions of how much hardening investment is prudent and where that investment should be made, it was necessary to include a Budget Optimization and Scheduling Model within the Storm Resilience Model. The Budget Optimization algorithm develops the project plan and associated benefits over a range of budget levels to identify a point of diminishing returns where additional investment provides very little return. The Project Scheduling component uses the preferred budget level and develops an executable plan by prioritizing projects that provide the

most benefit while balancing TEC’s technical constraints. I outline this in more detail below.

**3. MAJOR STORMS EVENT DATABASE**

**Q19. Please provide an overview of the Major Storms Event Database and how it was developed.**

**A19.** The Major Storms Event Database includes the ‘universe’ of storm events that could impact TEC’s service territory over the next 50 years. The database describes the phases of resilience (Figure 1) for the TEC high-level system perspective for a range of storm stressors. It was developed collaboratively between TEC and 1898 & Co. It utilizes information from the National Oceanic and Atmospheric Administration (NOAA) database of major storm events, TEC historical storm reports, available information on the impact of major storms to other utilities, and TEC experience in storm recovery. From that information, 13 unique storm types were observed to impact the TEC service territory. For each of the storm types, various storm scenarios were developed to capture the range of probabilities and impacts of each storm type. In total, 99 storms scenarios were developed to capture the ‘universe’ of storm events to impact the TEC service territory. Table 3 provides a summary of the

Major Storms Event Database. The table includes the ranges of probabilities, restoration costs, impact to the system, and duration of the event.

**Table 3: Major Storms Event Database Overview**

| 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 |

**Q20. What does the NOAA data show on the number and types of**

**major storm events to impact the TEC service territory?**

**A20.** The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 167 years, beginning in 1852. The NOAA major events 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 4 on the page below includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1852.

**Table 4: Historical Storm Summary from NOAA**

| 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 |

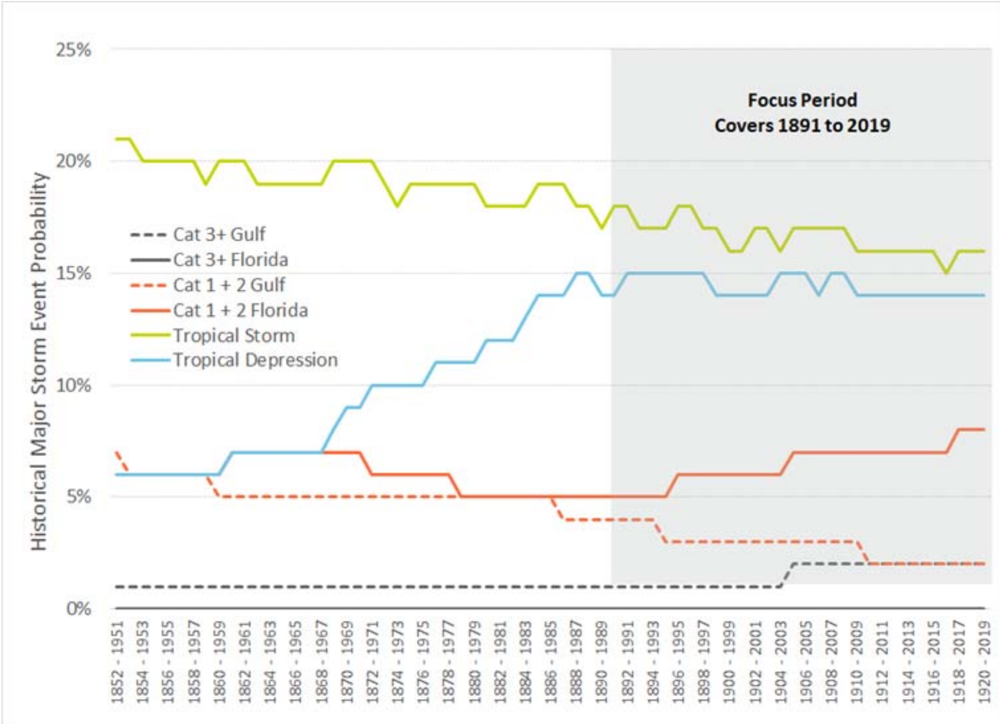
Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Table 4 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.

**Q21. What analysis of this historical storm information was done to determine the storm probability ranges?**

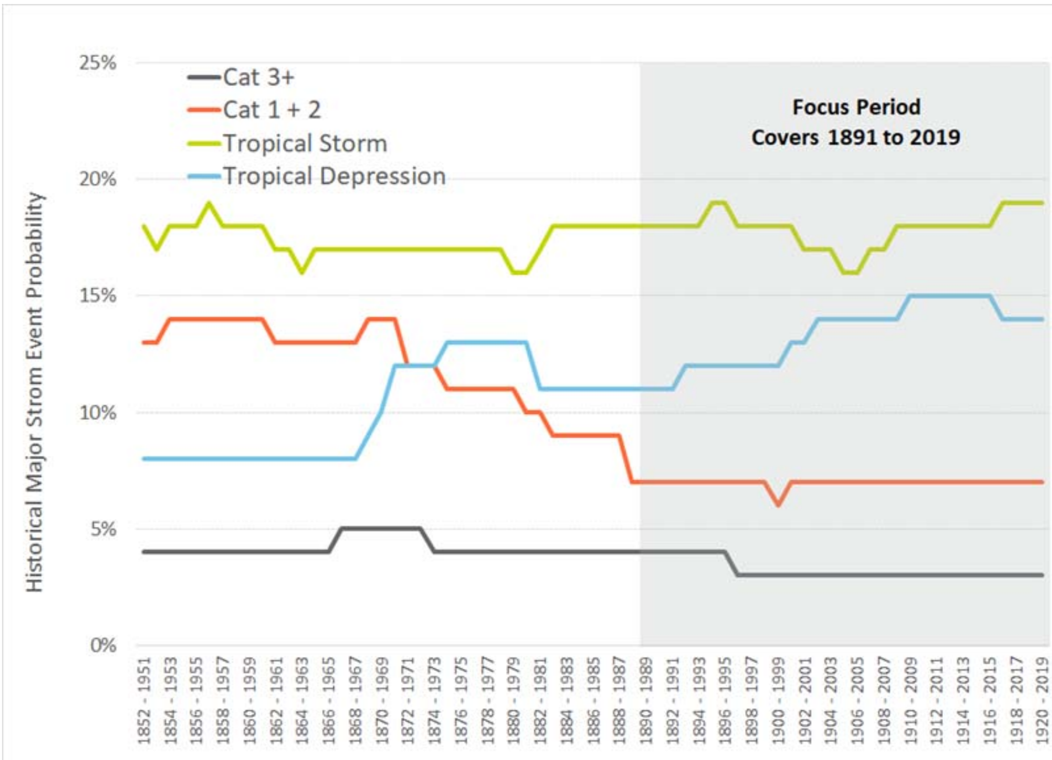
**A21.** 1898 & Co. converted the storm information from Table 4 above to show the total storm count for 100-year rolling average starting with the period of 1852 to 1951 ending with the period 1920 to 2019. This provides 69, 100 year periods. This was done for each of the 13 unique storm events. The counts of each 100 year period for each storm type were then converted to probabilities. Starting on the page below, Figure 3, Figure 4, and Figure 5 show the 100 year rolling storm probability for “direct hits” (50 miles), “partial hits” (51 to 100 miles), and “peripheral hits” (101 – 150 miles), respectively.

**Figure 3: "Direct Hits" (50 Miles) 100 Year Rolling Probability**



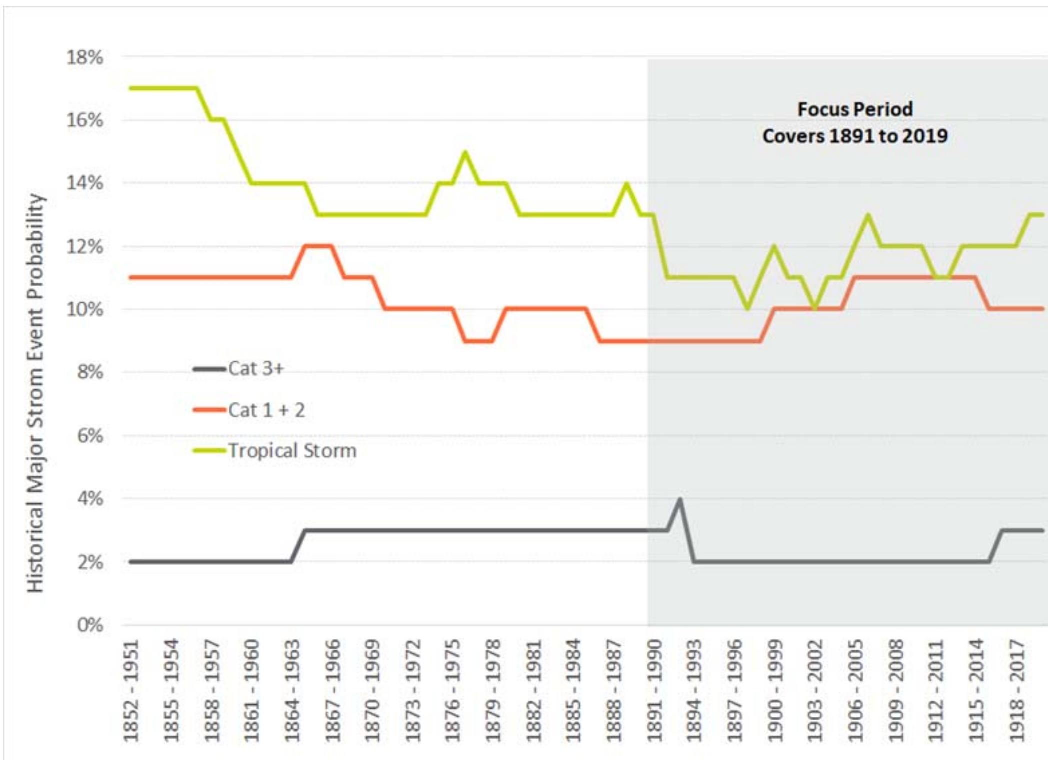

Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

**Figure 4: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability**




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

**Figure 5: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability**




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

Each of the figures show a relative stability in the 100 year probability levels for the last 30 periods corresponding to storm events from 1891 through 2019. This time horizon served as the basis for developing the probability ranges for the 13 unique storm events.

**Q22. How were the storm impact ranges developed?**

**A22.** The range of system impacts for each storm scenario were developed based on historical storm reports from TEC and augmented by the TEC's team experience with historical storm events. The database includes events that have not recently impacted TEC's service territory. The approach followed an iterative process of filling out more known impact information from recent events and developing impacts for those events without impact data based on their relative storm strength to the more known events.

**4. STORM IMPACT MODEL**

**Q23. Please provide an overview of the Storm Impact Model.**

**A23.** The Storm Impact Model describes the phases of resilience, Figure 1, for each potential hardening project on the TEC T&D system for each storm stressor scenario from the Major Storms Event Database. 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 the 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, CMI, and monetized CMI perspective.

**Q24. You have mentioned that the Storm Resilience Model employs a data-driven decision-making methodology. Please describe what core data sets that are in the model and how they are used in the resilience benefit calculation.**

**A24.** The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms at a very granular system level to model the benefits of each hardening project for each storm scenario. TEC’s data systems include a connectivity model that allows for the linkage of three foundational data sets used in the Storm Impact Model – the Geographical Information System (GIS), the Outage Management System (OMS), and Customer.

**GIS** - 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 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. The strategic assignment of assets to projects and the value of the approach is discussed above.

**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.

**Customer** - The third foundational data set is customer count and customer type information that featured connectivity to the GIS and OMS systems. This allowed the Storm Impact Model to directly link the number and type of customers impacted to each project and the project's assets. This customer information is included for every distribution asset in TEC system. The customer information is used within the Storm Impact Model to calculate each storms CMI (customers affected * outage duration) for each lateral or feeder project.

**Vegetation Density** - 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 (approximately 240,000 spans) utilizing tree canopy data and geospatial analytics.

**Wood Pole Condition** - 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.

**Wind Zones** - 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 higher closer to the coast and lower the further inland. 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.

**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. The Storm Impact Model performs a geospatial analysis of each structure to identify if there is road access or if the asset is in a deep right-of-way (ROW).

**Flood Modeling** - The model also includes 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.

**Q25. What were the results of the vegetation density algorithm?**

**A25.** Figure 6 and Figure 7 on the page below 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 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 6: Vegetation Density on TEC Primary Conductor**

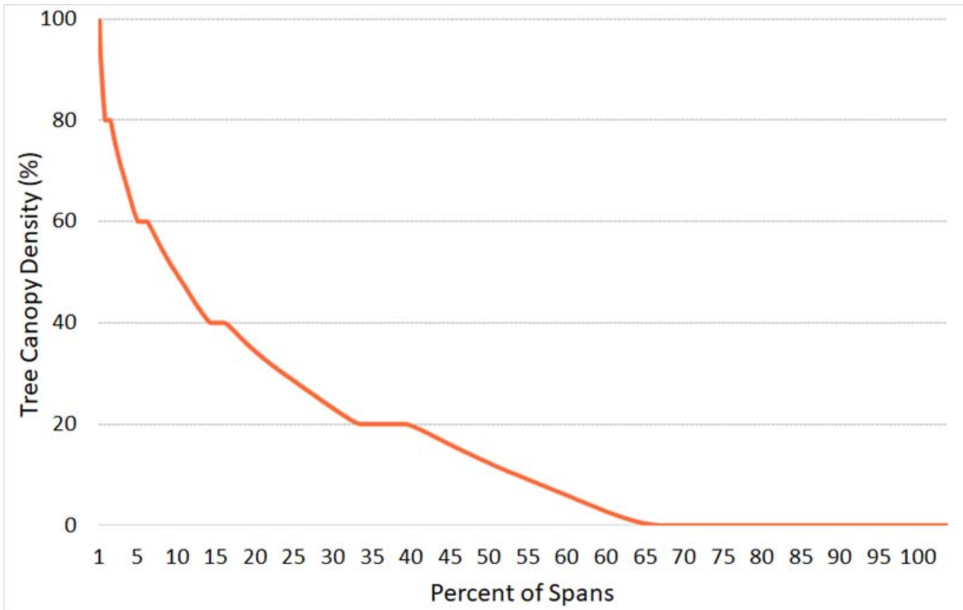
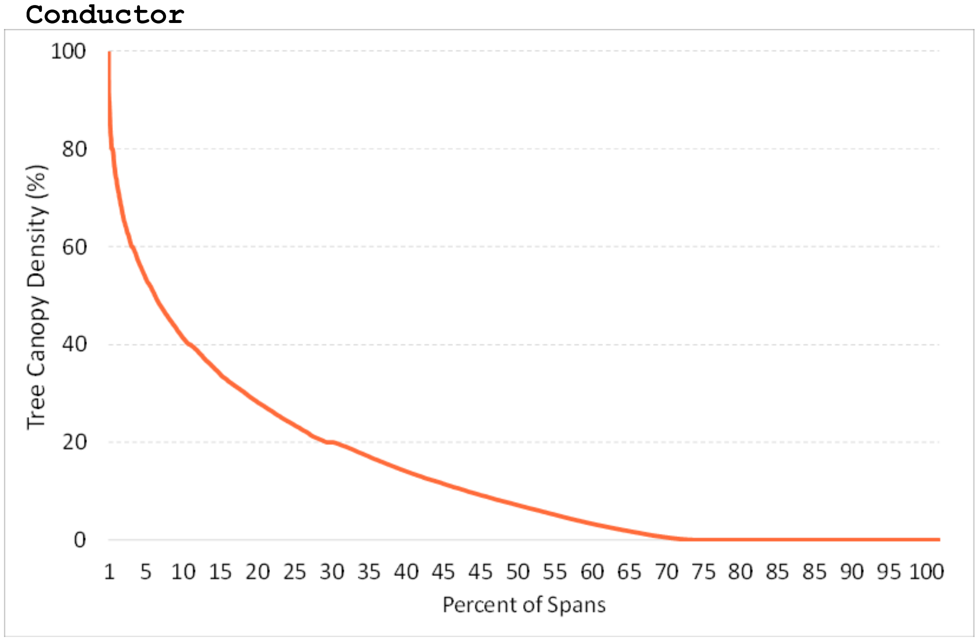



**Figure 7: Vegetation Density on TEC Transmission Conductor**



**Q26. How are asset and system failures during major storm events identified in the Storm Impact Model hardening projects?**

**A26.** The Storm Impact Model identifies system failures based on the primary failure mode of the asset base. The model identifies the parts of the system that are likely to fail given the specific storm event from the Major Storms Event Database.

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 utilizes 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 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. Only the storm scenarios with hurricanes coming from the Gulf of Mexico provide the necessary condition for storm surge that would cause substation flooding.

The site access dataset includes a hierarchy of the impacted circuits. Using this hierarchy, each site access LOF is equal to the total LOF of the circuits it provides access to.

**Q27. How are restoration costs allocated to the asset base for each major storm events?**

**A27.** Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration cost multipliers above planned replacement costs. 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. For each storm event, the restoration costs at the asset level are aggregated up to the project level and then weighted based on the project LOF and the overall restoration costs outlined in the Major Event Storms Database.

**Q28. How are customer outage durations calculated in the model for each major storm event?**

**A28.** Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset and project 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 are also monetized.

**Q29. Why were CMI benefit monetized?**

**A29.** The CMI benefits were monetized for project prioritization purposes. The Storm Impact Model calculates each hardening project's CMI and restoration cost reduction for each storm scenario. In order to prioritize projects, a single prioritization metric is needed. Since CMI is in minutes and restoration costs is in dollars, the resilience-based planning approach monetized CMI. The monetized CMI benefit is combined with the restoration cost benefit for each project to calculate a total resilience benefit in dollars.

**Q30. How was the CMI benefit monetized?**

**A30.** CMI was monetized using DOE's ICE Calculator. The ICE Calculator is an electric outage 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 or resilience 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 ICE calculator incudes the cost of an outage for different types of customers. The calculator was extrapolated for the longer outage durations associated with 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.

**Q31. How are the storm specific resilience benefits calculated for each project by major storm event?**

**A31.** 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. RESILIENCE BENEFIT MODULE**

**Q32. Please provide an overview of the Resilience Benefit Calculation Module**

**A32.** 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.

**Q33. What economic assumptions are used in the life-cycle Resilience Benefit Module?**

**A33.** The resilience net benefit calculation includes the following economic assumptions.

- 50 year time horizon – most of the hardening infrastructure will have an average service life of 50 or more years.
- 2 percent escalation rate
- 6 percent discount rate

**Q34. How were hardening project costs determined?**

**A34.** Project costs were estimated for 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 were then multiplied by unit cost estimates to calculate the project costs.

**Distribution Lateral Undergrounding** – The GIS and accessibility algorithm calculated the following scope items for each of the lateral undergrounding projects:

- 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.

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.

**Transmission Asset Upgrades** - 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.

**Substation Extreme Weather Hardening** - 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.

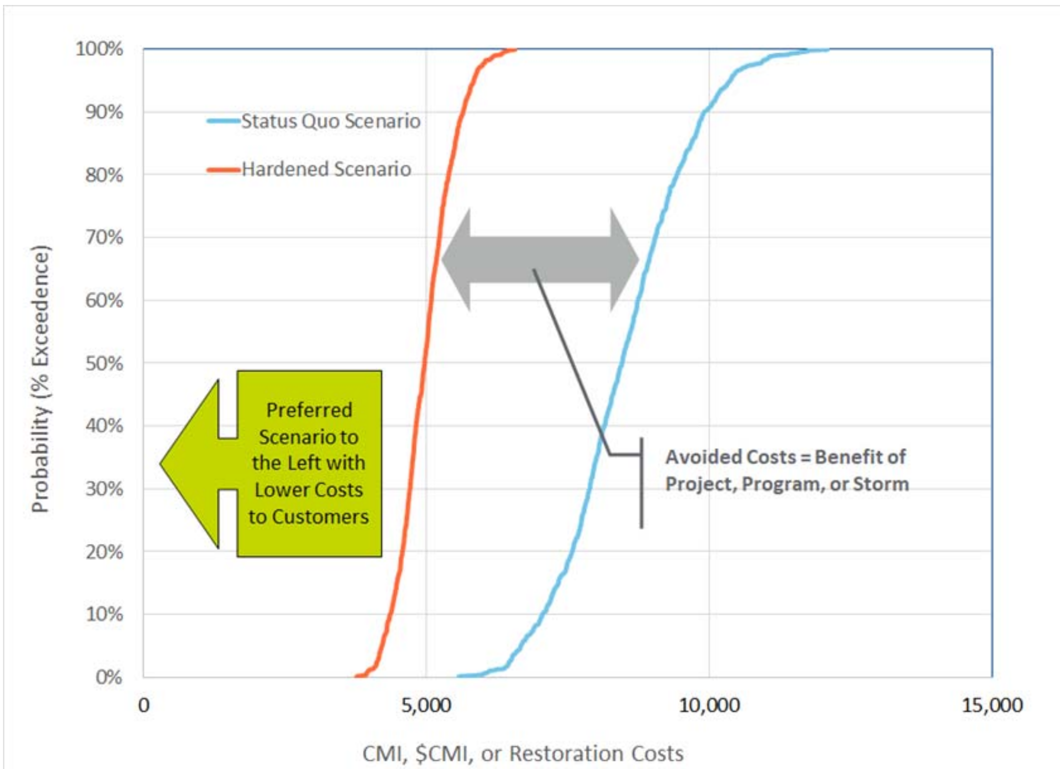
**Distribution Overhead Feeder Hardening** - The distribution overhead feeder hardening project costs are based on the number of wood poles that don’t meet current design standards for storm hardening and the cost to include automation. TEC provided unit replacement costs based on the accessibility of the pole as well as the cost to add automation to each circuit. Automation hardening cost estimates include the cost to add reclosers, pole replacements, re-conductor portions of the line, and substation upgrades that may be needed to handle load transfer.

**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.

**Q35. How are the resilience results of the Monte Carlo Simulation displayed and how should they be interpreted?**

**A35.** 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 8 on the page below shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios.

**Figure 8: Status Quo and Hardened Results Distribution Example**



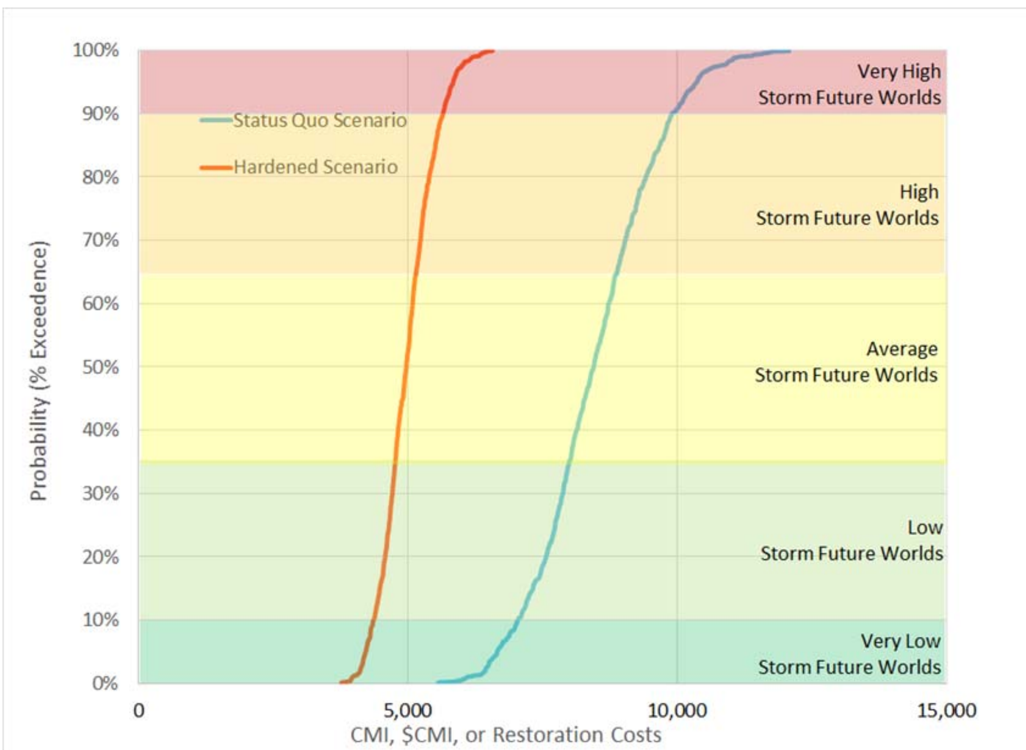

Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

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.

**Q36. How do S-Curves map to potential Future Storm Worlds?**

**A36.** Figure 9 below provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

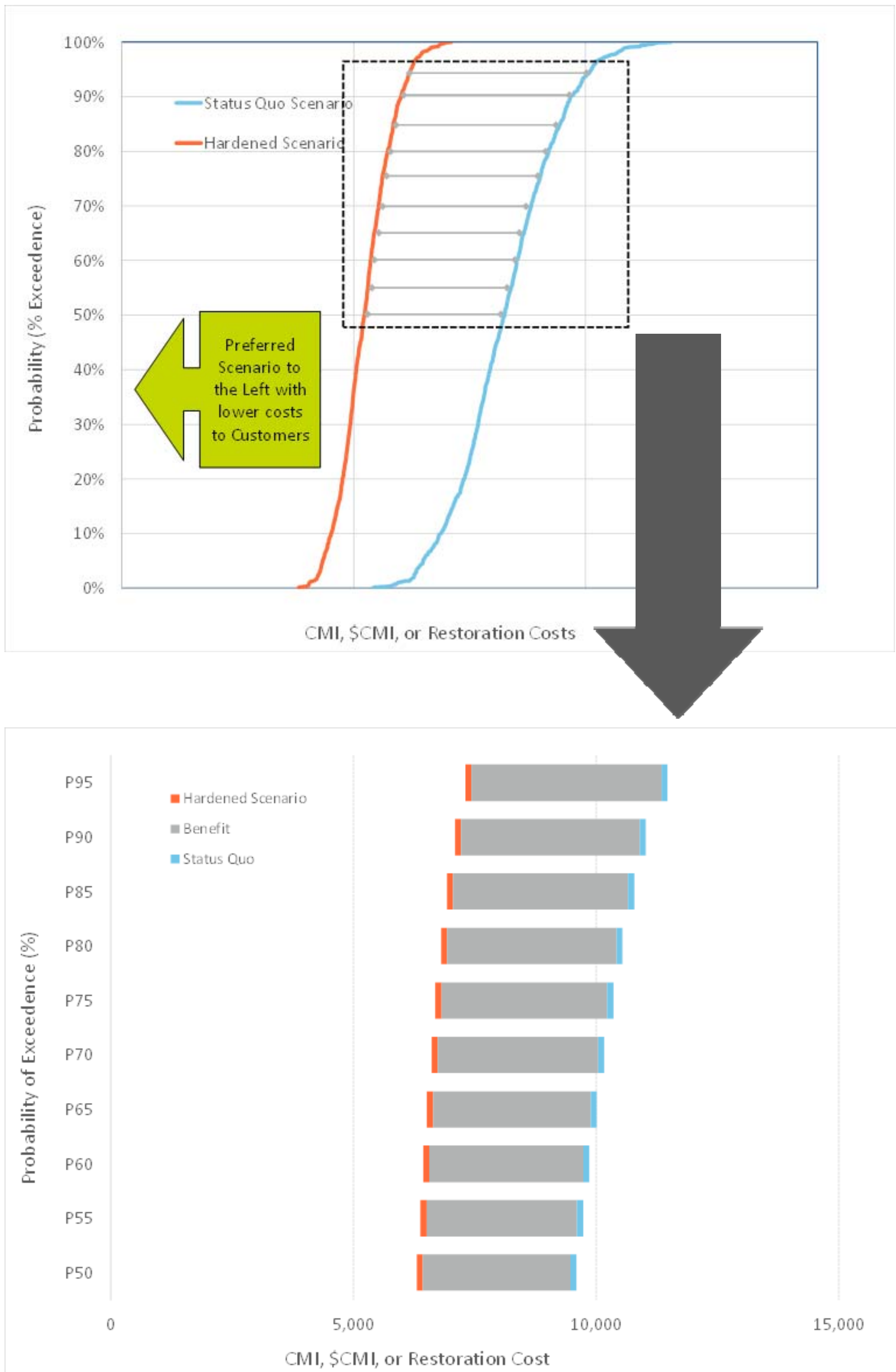
**Figure 9: S-Curves and Future Storms**



**Q37. How are the S-Curves used to display the resilience benefit results?**

**A37.** 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 resilience results 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 10 on the page below illustrates this concept of looking at the top part of the S-curves and showing the P-values.

**Figure 10: S-Curves and Resilience Focus**



**Q38. Please describe the analysis to calculate resilience benefit for automation hardening projects.**

**A38.** 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 1.

The resilience benefit for feeder automation was estimated using historical Major Event Day (MED) outage data from the OMS. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days. 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.

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. The Storm Resilience Model extrapolates the 19 years of benefit calculation to 50 years to match the time horizon of the other projects. Additionally, the CMI was monetized and discounted over the 50-year time horizon to calculate the net present value (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.

**Q39. Please provide an example of this calculation.**

**A39.** A historical outage may include a down pole from a storm event, causing the substation breaker to lock out resulting in a four-hour outage for 1,500 customers, or 360,000 CMI (4*1500*60). 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.

**Q40. What are the results of this analysis for the automation hardening projects?**

**A40.** Figure 11 and Figure 12 starting on the page below show the percent decrease in CMI and monetized CMI for all circuits ranked from highest to lowest from left to right. The figures also include the benefits to all outages.

**Figure 11: Automation Hardening Percent CMI Decrease**

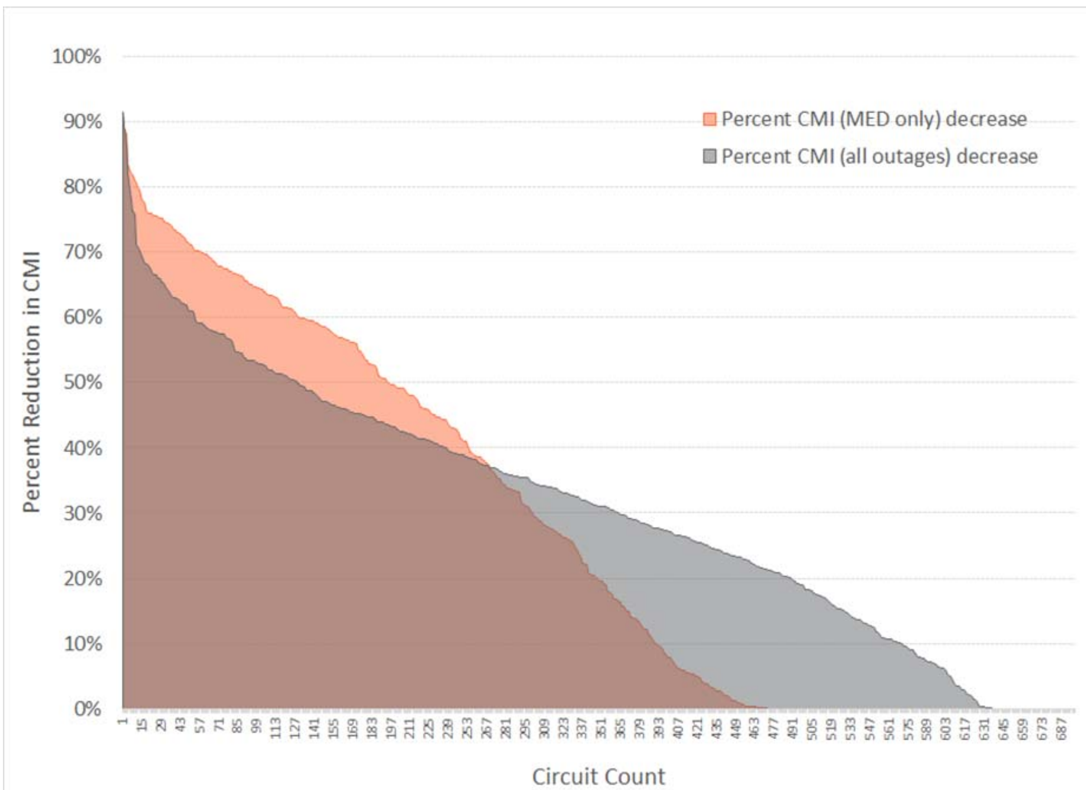
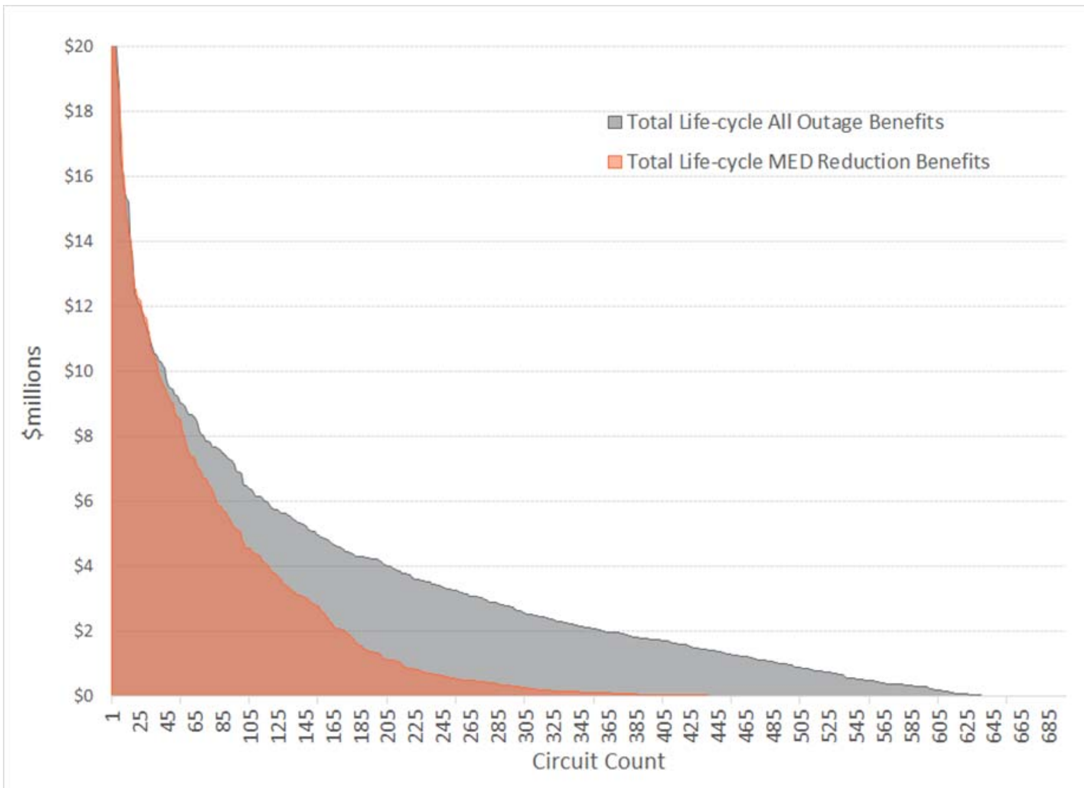


**Figure 12: Automation Hardening Monetization of CMI Decrease**




**Q41. What are the specific outputs from the Resilience Benefit module?**

**A41.** The Resilience Benefit Module includes the following values for each project:

- 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-based strategy, the approach focuses on the P50 and above values, specifically considering:

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

**6. BUDGET OPTIMIZATION AND PROJECT SCHEDULEING**

**Q42. How were hardening projects prioritized?**

**A42.** All the projects are evaluated and prioritized using the same criteria allowing all 20,459 projects to 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 (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, investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

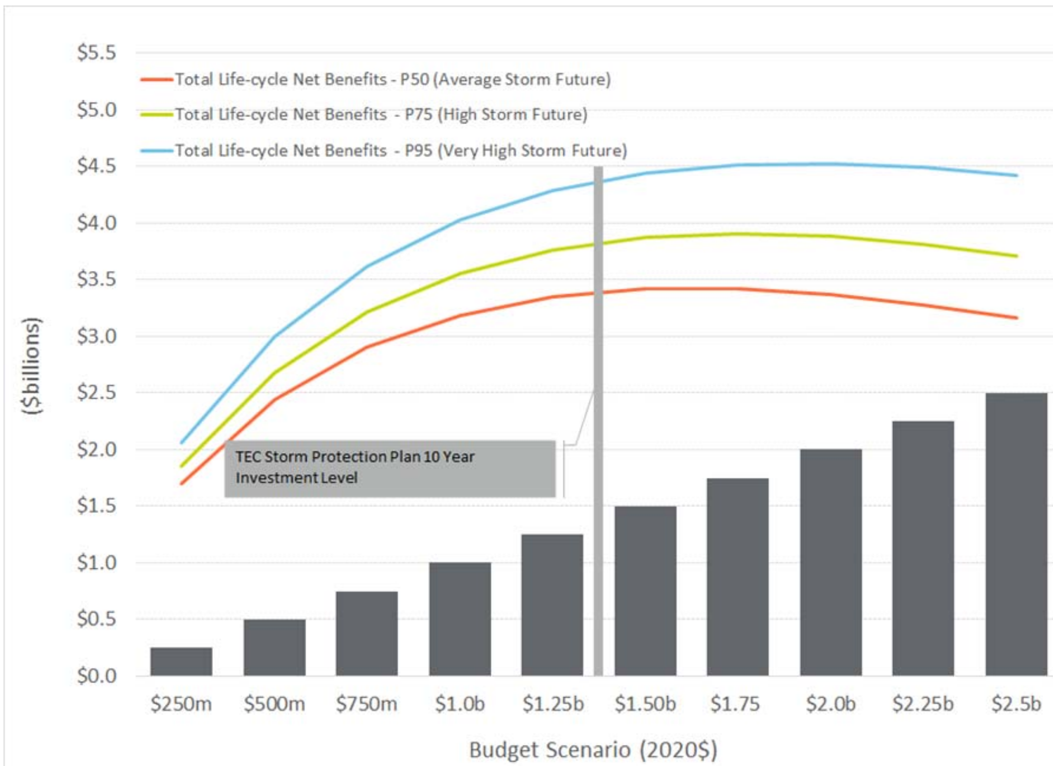
**Q43. How and why was the budget optimization performed?**

**A43.** 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. For each budget level, the optimization model selects the projects with the highest benefit cost ratio to hardening in the next 10 years. The model then strategically groups projects by type of program and circuit. For instance, all the selected laterals on a circuit are scheduled for undergrounding in the same year. This allows TEC to gain capital deployment efficiencies by deploying resources to the same geographical area at one time.

**Q44. What were the results of the budget optimization analysis?**

**A44.** Figure 13 on the page below 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 13: 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.

**Q45. What conclusions can be made from the results of the budget optimization analysis?**

**A45.** The budget optimization results show that TEC's 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.

**Q46. How was the overall investment level set and projects selected?**

**A46.** 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)

**7. RESILIENCE BENEFIT RESULTS**

**Q47. What is the investment profile of the Storm Protection Plan?**

**A47.** Table 5 on the page below 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.

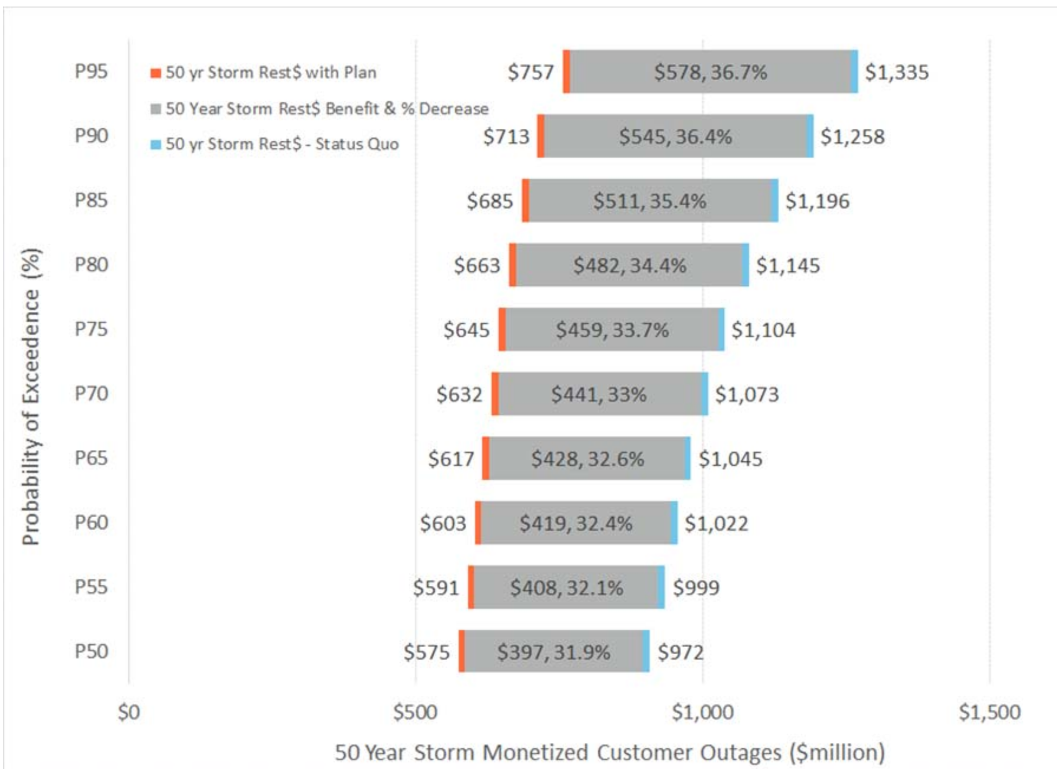
**Table 5: Storm Protection Plan Investment Profile by Program (Nominal $000)**

| 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 |

**Q48. What are the restoration cost benefits of the plan?**

**A48.** Figure 14 on the page below 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 14: Storm Protection Plan Restoration Cost Benefit**

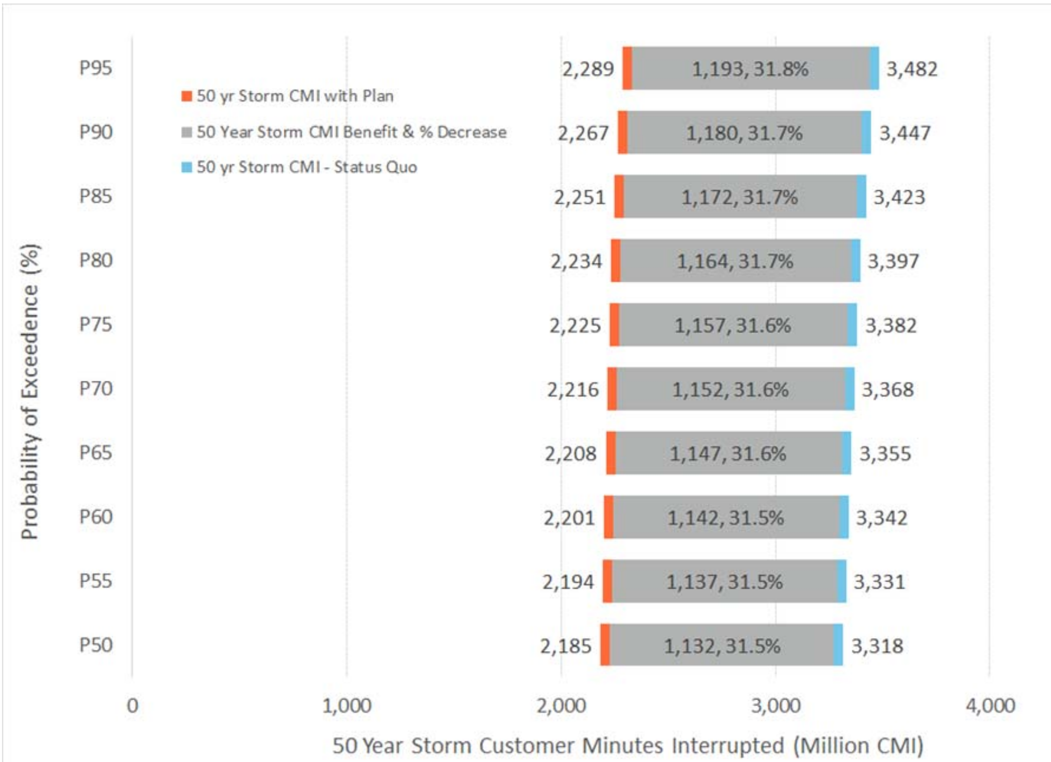



The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400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

**Q49. What are the customer outage benefits of the plan?**

**A49.** Figure 15 on the page below 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 15: Storm Protection Plan Customer Benefit**




**Q50. What are the key take-aways from how resilience-based planning assessment was performed?**

**A50.** The follow are the key take-aways from how the resilience-based planning assessment was performed in the Storm Resilience Model:

- **Customer and Asset Centric:** The model is foundationally customer and asset centric in how it "thinks" with the alignment of assets to protection devices and protection devices to customer information (number, type, and priority). Further, the focus of investment to hardening all asset weak links that serve customers shows that the Storm Resilience Model is directly aligned with the intent of the statute to identify hardening projects that provide the most benefit to customers. Additionally, with this customer and asset centric approach, the specific benefits required from the statute can be calculated, restoration cost saving and impact to customers in terms of CMI, more accurately.

- **Comprehensive:** The comprehensive nature of the assessment is best practice, by considering and evaluating nearly the entire T&D system the results of the hardening plan provide confidence that portions of the TEC system are not overlooked for potential resilience benefit.
- **Consistency:** The model calculates benefits consistently for all projects. The model carefully normalizes for more accurate benefits calculation between asset types. For example, the model can compare a substation hardening project to an lateral undergrounding project. This is a

significant achievement allowing the assessment to perform project prioritization across the entire asset base for a range of budget scenarios. Without this capability, the assessment would not have been able to identify a point a diminishing returns, balance restoration and CMI benefits, and calculate benefits on the same basis for the entire plan.

- **Rooted in Cause of Failure:** The Storm Resilience Model is rooted in the causes of asset and system failure from two perspectives. Firstly, the Major Storms Event Database outlines the range of storm stressors and the high level impact to the system. Secondly, the detailed data streams and algorithms within the Storm Impact Model are aligned with how assets fail, mainly vegetation density, asset condition, wind zone, and flood modeling. With this basis, hardening investment identification and prioritization provides a robust assessment to focus investment on the portions of the system that are more likely to fail in the major storm.
- **Drives Prudency:** The assessment and modeling approach drive prudency for the Storm Protection Plan on two main levels. Firstly, the granularity of potential hardening projects, over 20,000,

allows TEC to invest in the portions of the system that provide the model value to customers. Without granularity, there is risk that parts of the system "ride the coat-tails" of needed investment causing efficient allocation of limited capital resources. Secondly, the budget optimization allows for the identification of the point of diminishing returns so that over investment in storm hardening is less likely.

- **Balanced:** Hardening projects include mitigation measures over all the four phases of resilience providing a diverse investment plan. Since storm events cannot be fully eliminated, the diversification allows TEC to provide a higher level of system resilience for customers.

**Q50. What conclusions can be made from the results of the resilience analysis?**

**A50.** 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 13) shows the investment level is right before the point of diminishing returns. This provides confidence that TEC's plan does not over invest in storm hardening.

- 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. This reinforces that TEC's plan is prudent and making hardening investments that provide customer

benefits.

- 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. From a storm hardening perspective alone, the hardening investment types and overall level are prudent providing maximum value to customers. These ‘blue sky’ benefits just further enhance the business case for TEC customers

On the whole, TEC’s storm hardening plan benefits assessment aligns with the requirements of the statue, shows prudency in the overall investment level and where hardening investment is focuses, provides maximum benefit to customers, and shows significant benefits to customers with a reasonable cost to buy down storm outages.

**8. CONCLUSION**

**Q51. Does this conclude your prepared verified direct testimony?**

**A51.** Yes.

NARUC

# Resilience for Black Sky Days

## Supplementing Reliability Metrics for Extraordinary and Hazardous Events

Dr. Paul Stockton

February 2014

The National Association of Regulatory Utility Commissioners

A report for the National Association of Regulatory Commissioners with support from the U.S. Department of Energy

# RESILIENCE FOR BLACK SKY DAYS

## SUPPLEMENTING RELIABILITY METRICS FOR EXTRAORDINARY AND HAZARDOUS EVENTS

**Paul N. Stockton**

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NARUC's *Resilience in Regulated Utilities* provides the basis for establishing common definitions and developing a methodology for utility commissioners and others to consider when exploring the regulatory issues regarding investments in utility resilience.[1] This companion report examines how commissioners can further define resilience as a regulatory term of art, and build additional tools to assess resilience initiatives, by focusing on *black sky days*: i.e., extraordinary and hazardous catastrophes utterly unlike the blue sky days during which utilities typically operate.

The resilience challenges posed by black sky days also go above and beyond those posed by Superstorm Sandy, the Derecho Storms of 2012, or other recent Major Outage Events (MOEs). Building resilience against Sandy-scale events is vital, given the increasing frequency and severity of such storms. This report will briefly survey the progress that Public Utility Commissions and utilities are making in that effort. Yet, commissioners also face the risk of outages lasting even longer and covering a wider area than those caused by Sandy. A range of natural and manmade hazards could create "worse than Sandy" events. Federal and State emergency management agencies are treating preparedness for such catastrophes as a rapidly growing priority. These extraordinary and hazardous events will pose special risks to the resilience of electric utilities. Accordingly, State Commissions may wish to proactively consider assessment frameworks for investments in resilience that are structured to account not only for Sandy-scale major outage events, but also for black sky days.

If a State Commission determines that it is interested in exploring what would be needed for preparedness against the worst effects of black sky events, perhaps the best place to start would be the foundational metrics already in place for electric reliability. Metrics for resilience should *supplement*, not replace, the proven reliability metrics that have been refined over many decades. This study provides the starting point to do so by proposing a definition of a black sky day (versus MOEs) in terms of the percentage of utility customers experiencing an outage and the duration of the event. The study also examines where reliability metrics fall short of the assessment tools that commissioners will need for such extraordinary and hazardous events. In particular, commissioners and their staffs may want to assess how cascading failures of critical infrastructure in such events could create unprecedented problems for power restoration, and "look under the hood" of utility restoration plans and capabilities. Commissioners may want to collaborate more closely with State emergency management and energy assurance officials to account for specific catastrophic risks in their region, and expand partnerships with these officials to strengthen grid resilience. Existing enterprise risk management and cost-effectiveness methodologies may also need to be refined to account for black sky days, given the potentially massive scale of their consequences and (especially for manmade events) the uncertainty of their likelihood.

Many of these assessment efforts are also likely to be useful for Sandy-scale major outage events. Indeed, by developing ways to fill the assessment gaps highlighted by black sky days, it should be possible to "work back towards the middle" of the spectrum of events, and apply these initiatives to less catastrophic but more frequent electric outages. Working in this direction

[1] Keogh, Miles, and Christina Cody, (2013) *Resilience in Regulated Utilities*, NARUC, November 13, 2013

might also be integrated with efforts taking the opposite approach: that is, analyzing how resilience initiatives for MOEs might be scaled up and modified as needed for black sky days.

Creating such an overarching assessment framework for resilience will almost certainly require years to complete. Moreover, as with reliability metrics, that development process can best be advanced by a collaborative dialogue between commissioners and their staffs, utilities, Regional Transmission Organizations (RTOs) and Independent Service Operators (ISOs), and other stakeholders. To help advance that dialog, this study concludes with a set of questions for informal discussions and consensus-building outside the context of rate cases.

## I. Defining Resilience and Differentiating It from Reliability

NARUC's *Resilience in Regulated Utilities* (hereinafter referred to as the NARUC Resilience Report) notes that resilience has been defined in a variety of ways.[2] Many definitions, however, are similar to that provided by Presidential Policy Directive 21 (PPD-21), which defines resilience as "the ability to prepare for and adapt to changing conditions and *withstand* and *recover rapidly* from disruptions [emphasis added]. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring incidents."[3]

In some respects, this definition of broad resilience would fit with the system of metrics developed to assess reliability. Measures of electric outage frequency, such as the System Average Interruption Frequency Index (SAIFI), can help commissioners assess the ability of utilities to "withstand" incidents without incurring a loss of service. Measures of outage duration, such as the System Average Interruption Duration Index (SAIDI), can help assess the ability of utilities to "recover rapidly" from disruptions. Reducing the frequency and duration of outages will remain an essential goal for PUCs, and reliability metrics provide the indispensable foundation on which to build a framework to assess resilience. Appendix A summarizes reliability metrics that help provide this foundation. Yet, as severe storms and other major outage events have become more frequent, issues of whether and how to fit those events into measures of reliability have come to the fore -- with important implications for building assessment tools for the still more hazardous black sky days.

### A. Major Outage Events (MOEs): From Reliability to Resilience

Most of the days during the course of a year are blue sky days - that is, days without major storms or other potential external sources of service interruptions. Of course, interruptions can still be caused by animals (squirrels need better power line safety training!), foliage, equipment that fails due to age, and other hazards. SAIDI and SAIFI are perfectly attuned to assess the frequency and duration of such outages over the course of a reporting period, as well as those occurring on what we might call "gray sky" days created by low-intensity weather events. These metrics are essential to help commissioners assess proposed investments to improve *availability*, or day-to-day utility performance.[4]

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[2] NARUC (Keogh, et al., 2013) pp. 4-6.
[3] *Presidential Policy Directive -- Critical Infrastructure Security and Resilience*, February 12, 2013,
[4] Warren, Cheryl, (2005) *Measuring Performance of Electric Power Distribution Systems, IEEE Std 1366-2003*,

In addition, however, a growing number of State PUCs require utilities to establish a separate reliability reporting category for Major Outage Events such as Hurricane Irene (2011), the Derecho Storms (2012), and Superstorm Sandy. The Institute of Electric and Electronics Engineers (IEEE) argues that segmenting reliability data into two distinct sets for review in this fashion offers important advantages. In particular, collecting data on MOEs facilitates the review of how utilities respond to crisis events, as opposed to reliability in the day-to-day operating environment that typifies a one year or multi-year assessment period.[5]

Many states have yet to require their utilities to provide separate reporting on Major Outage Events.[6] Moreover, for the states that do collect reliability data for MOEs, varying definitions exist for a "major" event. Some identify MOEs in terms of specific numbers of customer service interruptions. One such definition, for example, characterizes a major power outage as affecting at least 1,000 customers and entailing a total downtime of at least 1,000,000 customer hours.[7] The problem with this definitional approach is that one size will not fit all: a state with a small population might categorize such an event as much more catastrophic than a state with ten times as many customers. Another approach is provided by the "2.5 Beta Methodology" provided in IEEE Standard 1366-2003. Under this definition, major event days occur when the daily System SAIDI exceeds a threshold based on historical outage data in the state.[8] A number of State PUCs have also adopted threshold criteria for MOEs based on sustained outages that exceed a certain percentage of a utility's customers and/or or a specific number of customers who experience outages. California, for example, specifies that a major outage occurs when 10 percent of an electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service. For utilities with less than 150,000 customers within California, a major outage occurs when 50 percent of the utility's serviceable customers experience such an interruption.[9]

Regardless of definition, however, collecting reliability data on MOEs can allow commissioners to more clearly assess a key focus of resilience – that is, *recovery*, which reflects how quickly utilities can "bounce back" after disasters and restore service when a crisis occurs. Maryland, for example, has established requirements for MOE reporting that include not only average duration

[5] Warren (2005)
[6] Eto, Joseph, Kristina Hamachi LaCommare, Peter Larsen, Annika Todd, and Emily Fisher (2012). *An Examination of temporal trends in Electricity Reliability Based on Reports from U.S. Electric Utilities*, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley CA. January, 2012;
Rouse, Greg and John Kelly, (2011) *Electricity Reliability: Problems, Progress and Policy Solutions*, Galvin Electricity Initiative, February 2011,
[7] McLinn, James, (2009) "Major Power Outages in the US, and Around the World," IEEE Reliability Society 2009 Annual Technology Report, p. 1,
[8] Warren (2005)
[9] California Public Utility Commission, *Public Order No. 166*, Maryland's reporting threshold for MOE's is set at events where: a) more than 10 percent or 1000,000, whichever is less, of the electric utility's Maryland customers experience a sustained interruption of service, and the restoration of service to any of these customers takes more than 24 hours; or b) the Federal, State or local government declares and official state of emergency in the utility's service territory. Maryland Public Service Commission, COMAR 20.50.01.03. B (27); Sustained outages exceed 10 percent of a company's customers or 100,000 customers, whichever is less. See COMAR 20.50.07.07;
For an example of a State PPUC that sets utility-specific criteria for MOE's see State of New York Public Service Commission, *PSC Redefines Major Outages for Con Edison*, June 18, 2008

of customer service interruption, but also more detailed data on factors that can help accelerate restoration, including information on the provision of outside assistance from other utilities.[10] Some PUCs are also specifying service restoration requirements in Major Outage Events. Maryland's PSC has established the following requirement:

> During each calendar year, a utility shall restore service within 50 hours, measured from when the utility knew or should have known of the outage to at least 95 percent of its customers experiencing sustained interruptions during Major Outage Events where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utilities total number of customers, whichever is less.[11]

B. Beyond Major Outage Events: Metrics for Black Sky Days

One feature shared by all current definitions of Major Outage Events is that they have no upper boundary -- no cutoff point that could help commissioners and utilities differentiate between events causing power outages for 10% of customers versus 90%. The IEEE's Distribution Reliability Working Group has found that this lack of an upper boundary creates problems for measuring utility performance. IEEE found that when companies applied the Beta Method threshold, unusually large, catastrophic events would distort overall measures of SAIDI performance. IEEEE is now developing methods for handling "extreme outlier days" so that performance measures are not "tainted" by such extreme events.[12]

There are also vastly more important reasons to focus on extreme threats to the grid as a unique challenge for reliability and resilience. As will be explained in the next section, catastrophic events pose risks to the grid over and above those created by Major Outage Events, and will likely require the development of new risk management and resilience initiatives. The NARUC Resilience Report set the stage for this development effort by proposing to narrow the definition of resilience. The Report defines resilience as the "robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an *extraordinary and hazardous event*" [emphasis added].[13] To build an assessment framework for extraordinary and hazardous events, which this study terms black sky events, it will be helpful to further clarify the definition of such events and differentiate them from Major Outage Events.

The best way to do so is to set an upper threshold for MOEs, above which events would be categorized as black sky/extraordinary and hazardous events. Two options exist to set such a threshold. The first would be to build on the Beta Method approach in IEEE Standard 1366, and identify black sky events when the daily System SAIDI exceeds a threshold (based on historical outage data in the State) much higher than the Standard set for the lower boundary of MOEs. A methodology of this kind may be able to provide a statistically valid and broadly applicable

[10] Maryland Office of the Secretary of State. *Major Outage Event Reporting,*
[11] Maryland Public Utility Commission, (2013). *Order No. 85385, In the Matter of the Electric Service Interruptions in the State of Maryland due to the June 29, 2012 Derecho Storm,* February 27, 2013, p. 15
[12] McDaniel, John, *Uses of IEEE 1366 and Catastrophic Days*
[13] NARUC (Keogh, et al, 2013) p. 5

threshold for black sky events, which would be especially useful to facilitate cross-State performance assessments.[14]

A second option would be to establish a black sky threshold for specific utilities or States, based on a specified percentage of customers experiencing service interruptions and a specified duration for the outage. Defining black sky events as those where a minimum of 50 percent of customers lose power would easily put a number of recent severe storms into that category, depending on the duration criteria that were chosen. In the Derecho storm, for example, 77 percent of Pepco customers experienced outages during the peak of the Derecho Storm.[15] Moving such outlier storms into the category of black sky events, versus keeping them in the MOE category, would help resolve the problem identified by the IEEE of having these storms "taint the data" for SAIDI reporting on major events.

Yet, if commissioners and utilities are interested in proactively exploring this issue, they may also want to consider setting the black sky threshold above the SAIDI levels experienced in the Derecho Storm, Sandy, or any other event experienced to date. Doing so would help focus analysis on the special resilience challenges and regulatory issues posed by the extraordinary and hazardous risks examined in the remainder of the paper. This study proposes to define black sky days as events where more than 90% of a utility's customers experience outages of more than 25 days. This definition would create a threshold well above any recent weather event by combining the most severe characteristics of both Sandy and Hurricane Katrina -- what might be termed the "Santrina" benchmark.[16]

Specific threshold components:

- *Percentage of customers without power*. In Superstorm Sandy, utilities such as the Long Island Power Authority (LIPA) faced extraordinarily large-scale outages, with the utility estimating that 90% of its 1.1 million customers lost power at the peak of the event.[17] The proposed definition of back sky days would be for events that exceed this 90% level.

- *Event duration*. Measured by how many days it took to restore service to 95% of customers, Hurricane Katrina (2005) was a more extreme event than Sandy. LIPA and other New York utilities restored power to 95% of its customers 13 days after Sandy made landfall.[18] After 23 days in Katrina, only 75% of customers had their power

[14] Note, however, that after examining a number such options to identify catastrophic events, an IEEE working group found that thus far "no objective method has been devised that can be applied universally." That working group recommended instead that the threshold for catastrophic events should be determined on an individual company basis by regulators and utilities. McDaniel, (p. 15)
[15] Maryland PSC, *Order No. 85385*, p. 9.
[16] I offer special thanks to Christina Cody of NARUC for suggesting this term.
[17] Long Island Power Authority (LIPA), (2013) *Presentation: Investor Update Conference Call*, January 16, 2013
[18] "Length of Outage after Sandy Not Unusual," (2012) Associated Press, November 16, 2012;
LIPA, (2012) "LIPA Completes Restoration to 95% of Homes and Businesses that are safe to Receive Power," November 11, 2012

restored before Hurricane Rita struck the affected area and created additional outages. The proposed definition for black sky days would be 25 days or more.[19]

## II. Black Sky Risks and Resilience Challenges

Across the Federal Government and in a growing number of States, emergency management leaders are shifting their preparedness efforts towards events "worse than Sandy." The Federal Emergency Management Agency (FEMA), which leads Federal disaster response efforts when States request assistance, has helped drive this new focus on catastrophic events. FEMA Administrator Craig Fugate emphasizes that "We need to understand that as bad as Sandy was, that may not be the benchmark that we need to limit ourselves to. There are threats and potential disasters that could be even larger."[20] Administrator Fugate has made planning and preparing for such catastrophes a top priority for the Agency.[21]

FEMA is partnering with States across the nation to build plans for catastrophic events, many of which focus on the specific hazards in that State that pose the greatest risk -- that is, 1) hazards that are most *likely* to strike; 2) are hazards to which the State is especially *vulnerable*; and 3) are hazards that would have most devastating *consequences* should an event occur. California has three such plans for region-specific hazards from South to North: the Southern California Catastrophic Earthquake Response Plan, the Bay Area Readiness Response Plan, and the Cascadia Earthquake and Tsunami Response Plan.[22] Hawaii, Florida, and many other States are also building hazard-specific plans for events more destructive than they have ever before experienced.[23]

Many of these hazards pose risks of creating long-term, wide area outages at "Santrina" level or above -- i.e., where at least 90 percent of a utility's customers have lost power for at least 25 days. The New Madrid Seismic Zone exemplifies these risks. The New Madrid fault roughly parallels the Mississippi River, and produced of a 7.7 earthquake in 1812. A recurrence of that earthquake today (which was the focus of a 2011 National Level Exercise) would damage or destroy many hundreds of electric substations, high voltage transformers and transmission lines, generators, and other grid components over a multi-state region including Illinois, Indiana, Missouri, Arkansas, Kentucky, Mississippi, Tennessee, and potentially other States.[24] The Department of Energy assessed that such an event would not only disrupt power in the New Madrid region but far beyond, with outages potentially affecting 100-150 million people across

[19] "Length of Outage after Sandy Not Unusual" (AP, 2012)
[20] Miles, Donna. Northcom, "FEMA Build on Hurricane Sandy Response Lessons," January 14, 2013
[21] "Planning and preparing for catastrophic disasters is a top priority at FEMA," (2013) *Disaster Resource Guide 2013*,
[22] California Governor's Office of Emergency Services, *Catastrophic Planning.*
[23] Federal Emergency Management Agency (FEMA), FEMA, (2009) "Hawaii State Civil Defense Sign Catastrophic Plans into Operation," September 2, 2009; Florida Division of Emergency Management, (2011) *Catastrophic Planning Project Overview*, April 6, 2011,
[24] Mid America Earthquake Center, (2009) *Impact of New Madrid Seismic Zone Earthquakes on the Central USA, Vol. 1*, October 2009,

the Northeast, Southeast and Midwest United States.[25] The DOE report also found that the earthquake would cause breakages in ten interstate natural gas pipelines and damage oil pipelines and coal railway distribution systems as well.[26] Severe damage would also occur to the infrastructure on which utility power restoration crews depend on to repair or replace damaged equipment, including communications systems, gasoline and diesel fuel distribution systems, and critical bridges and roads, as well as "lifeline" infrastructure such as hospitals and water systems.[27]

In addition to these State- and region-specific hazards, power distribution systems in *all* States are at potential risk to nationwide hazards from both natural and manmade threats. Two studies commissioned by the North American Electric Reliability Corporation (NERC) are especially valuable for assessing these risks: *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System (2010),* and *Severe Impact Resilience: Considerations and Recommendations (2012).*[28] Both studies focus on risks with the potential to cause catastrophic impacts on the electric power system, but which either rarely occur or (in some cases) have not yet struck but may do so in the future. These risks include coordinated cyber, physical, and blended attacks; the electromagnetic pulse effects created by the high-altitude detonation of a nuclear weapon; and major natural disasters like earthquakes, tsunamis, large hurricanes, pandemics, and geomagnetic disturbances (GMD) caused by solar weather.

More recently, the Department of Energy and Executive Office of the President have issued studies examining how climate change will create risks of increasingly severe storms and other hazards to grid resilience.[29] Following the direction by the Federal Energy Regulatory Commission that NERC propose reliability standards for GMD on the bulk power system, attention is also growing to the potentially catastrophic risks posed by such events.[30] Disagreement persists over the degree to which a GMD event would cause physical damage to high voltage transformers and other critical grid components. However, after assessing the overall risks posed by GMD events on the scale of the Carrington event that occurred 154 years ago, Lloyds of London and other reinsurance companies have concluded that insurers face potentially massive exposure to business interruption and other claims. The Lloyd's study finds that while the probability of a Carrington-level event is relatively low at any given time, it is almost inevitable that one will occur eventually. The study also concludes that the total U.S.

[25] US Department of Energy, (2010) *DOE New Madrid Seismic Zone Electric Utility Workshop Summary Report*. August 25, 2010, pp. 2-4. Note that the DOE assessment was based on the simultaneous occurrence of both the New Madrid and Wabash faults
[26] DOE, (2010) pp. 4-7.
[27] Mid America Earthquake Center, Impact of New Madrid, and Central United States Earthquake Consortium, (2011). *CUSEC After-Action Report (AAR)*, pp. 50-1
[28] North American Electric Reliability Corporation (NERC), (2010) *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*, June 2010; NERC, (2012) *Severe Impact Resilience: Considerations and Recommendations*,
[29] Department of Energy, (2013) *U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather*, July 2013; Executive Office of the President, (2013) *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*, August 2013.
[30] Federal Energy Regulatory Commission, (2013) *Reliability Standards for Geomagnetic Disturbances*, May 16, 2013

population at risk of extended power outage in such a GMD event is between 20-40 million, with outage durations of 16 days to 1-2 years.[31]

Taken together, such events pose a characteristic set of potential consequences and power restoration challenges of black sky events. These distinguishing characteristics help clarify the special problems that assessment frameworks for black sky resilience will need to encompass, and (paired with data on event likelihood and vulnerability) can also help build an enterprise risk management approach for such events. Key potential consequences and power restoration challenges:

- *Massive, multi-state damage to critical power generation, transmission and distribution components*. Note that black sky events will likely cause such damage not only to distribution systems, but also to power generators and the high voltage transmission lines that are under the regulatory jurisdiction of FERC (versus PUCs), and are essential to distribution system functionality. Equipment repair and replacement challenges for very wide-area events -- which industry now terms "National Response Events" (NREs)[32] -- could entail extraordinary challenges for mutual aid, especially in responding to non-traditional threats such as coordinated cyber and/or kinetic attack. Large scale damage to high voltage transformers other difficult-to-replace grid components would create further challenges for restoration and resilience.

- *Disruption of energy infrastructure essential for fueling the grid*. In major earthquake or many other black sky events, interdependent infrastructure and systems essential for power generation (such as natural gas pipelines, water, transportation, communications, public health and safety, and other systems) might not only be disrupted by electricity outages, but would also suffer physical devastation on a multi-state scale. This damage would create a second contributor to event duration, over and above the damage to the electrical system.

- *Disruption of infrastructure critical for power restoration operations*. The infrastructure sectors most vital to support power restoration could themselves be severely disrupted. Destruction of cell towers and other communication system components would have an especially significant impact in this regard. Damage to roads and bridges essential to move utility crews and replacement grid components would further impede restoration operations, as would damage to the other supporting infrastructure on which they rely (such as the availability of fuel for utility vehicles). This downstream damage constitutes a third component of the overall restoration challenge.

- *Loss of emergency power to critical facilities and functions*. Hospitals, water and wastewater infrastructure, emergency operations centers, nursing homes, centralized food and pharmaceutical distribution nodes, and other facilities essential for public health and

[31] Lloyd's, Atmospheric and Environmental Research Inc., (2013) *Solar Storm Risk to the North American Electric Grid*, , 2013, p. 4 and *passim*.
[32] Edison Electric Institute, (2013) "*Overview of the electric Power Industry's Mutual Assistance Process During a National Response Event*, November 2013,

safety typically have emergency power generators and fuel stored on-site to power them. In a long duration, wide-area outage, however, these critical facilities would be disrupted as generators failed and demands for emergency fuel resupply outstripped supply (especially if fuel distribution systems were themselves disrupted). The Nuclear Regulatory Commission and its industry partners have made special arrangements to ensure that their emergency power needs can be met. However, chemical plants and other at-risk facilities could also pose risks to nearby population centers as emergency power generators and fuel supplies for them came under stress. And of course, as was highlighted in Fukushima, radiological or chemical events (and perhaps even the perceived possibility of such an event occurring) would greatly magnify the difficulties of power restoration and further lengthen outage duration.

- *Extraordinary Political Pressures*. Black sky events would also create a supercharged political environment for power restoration operations. Indeed, a black sky event will be the signature political crisis for every elected official in the affected region. Federal, state and local leaders will create urgent and incessant demands for information on Estimated Time of Restoration (ETRs), restoration priorities, and how scarce restoration resources are being allocated. Commissioners and utilities can expect that leadership engagement -- from the U.S. President on down -- would be vastly greater than even in Sandy-scale events, with attendant problems for setting and communicating ETRs and managing other crisis-driven restoration issues.

## III. Initiatives to Assess and Strengthen Resilience: Preliminary Steps

State Commissions will need to decide for themselves if exploring preparedness against the worst effects of black sky days is worthwhile. Many PUCs and utilities are already taking major steps to strengthen preparedness for Sandy or Derecho-scale major event outages.[33] However, to assess and incentivize proposals to build resilience against black sky days, commissioners and their staffs may want to further extend the range of their analysis and the scope of their interagency relationships. This section proposes that commissioners and utilities discuss how to do so along three lines of effort: 1) the development of additional assessment priorities and tools; 2) the creation of deeper partnerships with emergency management leaders and State officials responsible for energy assurance; and 3) the adaptation of enterprise risk management techniques to account for black sky days; and 4) the creation of new analytic approaches to assess the cost-effectiveness of initiatives targeted on these extreme and hazardous events.

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[33] For a comprehensive summary of these utility initiatives, see Edison Electric Institute, (2013) *Before and After the Storm*, January 2013; For additional proposed initiatives, including those timed to "smart gird" modernization, see The Gridwise Alliance, (2013) *Improving Electric Grid Reliability and Resilience Lessons Learned from Superstorm Sandy and other Extreme Events*, June 2013;
New York State 2100 Commission, (2012) *Recommendations to Improve the Strength and Resilience of the Empire State's Infrastructure,* November 2012; and the Office of Governor martin O'Malley, (2012) *Weathering the Storm: Report of the Grid Resiliency Task Force*, September 2012; Examples of Public Utility Commission order to improve resilience include the State of New Jersey Board of Public Utilities, (2013) *In the Matter of the Board's Review of the Utilities' Response to Hurricane Irene*," January 23, 2013; And Maryland Public Utility Commission, *Order No. 85385*, p.4 and p.17

A. Supplementing SAIFI, SAIDI, and CAIDI: New Priorities and Requirements for Assessing Resilience

As a measure of the frequency of power outages, SAIFI will be useful for certain extraordinary and hazardous threats. In particular, since electric power systems undergo near-constant probing by prospective attackers, and since the cyber weapons available to them continue to grow in potential destructiveness, it will be important to assess the frequency with which future computer network attacks (CNAs) create electric outages. That same assessment value helps justify the inclusion of outage avoidance in the definition of resilience.

Against a New Madrid earthquake or equivalently catastrophic event, however, it will be impossible to avoid power outages, and spending money to pursue such a goal would require limitless rate increases. The more appropriate objective for resilience will be to minimize service interruptions. Even limited progress in achieving that goal could have enormous benefits, since threats to public safety and the economy will rapidly escalate as emergency supplies become problematic. In theory, SAIDI could measure overall outage duration even in extraordinary and hazardous events. So could the Customer Average Interruption Duration Index (CAIDI), which helps assess the impact of an outage on an average customer by dividing how long each customer experiences an outage by how often they experience one. In practice, however, many States exclude longer duration events from SAIDI and other reliability metrics because including them would distort assessments of utility performance during normal operating days. An initial step that commissioners may want to make to adapt these reliability metrics for resilience purposes is to separate assessments of utility performance in catastrophic events versus blue sky and major outage events. [34]

For the much longer-term effort needed to identify and fill gaps in assessment tools for black sky events, commissioners and utilities may want to start by accounting for the special problems these events will create for power restoration, and by broadening their analysis beyond what a typical rate case would encompass. Moving into these areas of analysis could take some State PUCs beyond what is provided for in their existing regulatory processes and statutory authorities; those PUCs will need to carefully consider whether and how to pursue such an expanded role. To set the stage for considering such issues, and to help provide the basis for informal discussions with utilities on black sky assessment and investment priorities, topics to examine should include:

- *Assessments of power restoration requirements*. In an extraordinary and hazardous event, where N-1 or N-2 analysis will be inadequate for assessing requirements to mitigate damage to distribution system components, scaled-up analysis of such requirements (to N-20 or beyond) will be essential. Ongoing FEMA Region planning for Region-specific catastrophic hazards can help provide a basis for such analysis. New analytic techniques, particularly network analysis, may also help provide more effective assessments of requirements for replacement components, system redundancy options, and operational measures to mitigate the effects of damaged equipment in distribution systems (and

[34] Warren (2005), pp. 18-20; NARUC (Keogh et. al, 2013) pp. 7-8

perhaps also at least some consideration of bulk power system generation and high voltage transmission issues). The analysis should also include mitigating the risks posed by the disruption of the energy infrastructure on which the electric system depends, and the communications and other infrastructure critical for restoration. These assessments will help commissioners determine which investments will be most cost-effective in reducing event duration. Finally, given the dependence of distribution systems on bulk power system generation and high voltage transmission assets, and the risk that these assets may by severely damaged in a black sky event, commissioners may need to further broaden the scope of their resilience analysis to consider such issues.

- *Black Start.* As a further step towards looking "under the hood" of resilience requirements, commissioners may also want to discuss with utilities how they will use black start generators to launch the restoration of grid functionality, and better understand the "cranking path" that the utility will follow. Extraordinary and hazardous events may disrupt those paths and damage black start generators. During the past decade, the retirement of coal-fired power plants and stringent EPA regulations have helped spur a decline in black start capabilities for electricity and fuel systems in many regions. A large number of utilities are now in the process of strengthening their capacity to conduct black start operations. Analyzing requirements for such capabilities, and for emergency fuel and other supporting components of black start systems, could help commissioners determine whether additional investment in this realm would have significant risk-reduction benefits. Such an analysis may also require commissioners to look beyond distribution system issues and also examine bulk power system factors (potentially involving assets located in other States).

- *Assessments of mutual assistance mechanisms*. The Regional Mutual Assistance Group (RMAG) system provides a proven, highly effective system by which utilities can support each other with utility crews and other assets. Many municipal power systems and electric cooperatives also have strong mutual support arrangements. The Spare Transformer Equipment Program (STEP) and other mechanisms to share critical grid components between utilities further strengthen their ability to speed power restoration in large-scale power interruptions. Yet, as noted in a 2013 NARUC Resolution on major outage-triggering events, events of the scale of Sandy and beyond will require an even stronger resource sharing and allocation system (and, potentially, supporting efforts by State transportation agencies and other departments).[35] Under the leadership of the Edison Electric Institute, utilities are now developing major improvements to the RMAG system that will scale it for National Response Events. Commissioners would benefit from assessment tools that help them examine how proposed improvements to mutual assistance mechanisms can shorten restoration times in their States, and the degree to which cyber-related hazards and other non-traditional threats may render these mechanisms problematic.

[35]NARUC, (2013) *Resolution on Electric Utility Industry-Wide Response to Major Outage-Triggering Events*, 20 November 2013,

- *Assessing and incentivizing other operational improvements.* A growing number of States are encouraging utilities to adopt the Incident Command System (ICS) for event management and response.[36] ICS offers a proven, standardized, and highly effective way to organize infrastructure restoration operations when multiple organizations and agencies must coordinate their efforts (as would certainly be the case in a black sky event). Other ways to make operational improvements for resilience are proposed in NERC's *Severe Impact Resilience.* That study examines a range of operational measures to mitigate the effects of a catastrophic event on the bulk power system, including innovative ways to reroute power flows around damaged equipment and the development of new strategies for load shedding. Some of these operational measures might be adapted to strengthen distribution system resilience for black sky events.

- *Applying new technologies*. The Edison Electric Institute's report *Before and After the Storm* identifies a number "smart grid" technologies (including smart meters) that can speed power restoration by providing better situational awareness of outage locations and more effective real time monitoring of the grid.[37] Phasor measurement units may prove to be especially helpful in this regard. Gathering additional data on their actual effectiveness in reducing event duration in MOEs and other outages, and prioritizing the development of technologies tailored for long term/wide area service interruptions, could provide major resilience benefits for black sky days.

- *Prioritized restoration plans and guidelines.* In extraordinary and hazardous events, it may not be possible to restore power simultaneously to all the priorities that exist within a given service area. Special needs populations, police departments, life-sustaining infrastructure, and other critical customers will be increasingly at risk as emergency generators and fuel for them fall short of requirements. PUCs vary greatly in the degree to which they are briefed on utility restoration priorities, guidelines, and criteria for classifying customers. As part of the resilience focus on minimizing the impact of interruptions of service, commissioners and their staffs may want to examine these guidelines in greater detail, and perhaps even offer recommendations on them. They should also consider engaging with key customers who operate critical infrastructure that depend on reliable electricity in order to better understand the cascading effects on communities and the State associated with a long-term outage.

- *Preparedness against novel response challenges.* Non-traditional threats could require power restoration plans and capabilities very different from those that industry has developed for hurricanes, ice storms and other familiar hazards. Cyber threats exemplify this challenge. For investments to prevent and protect against cyber attacks, NARUC's *Cybersecurity for State Regulators 2.0* provides a comprehensive set of criteria and recommended actions (from a wide variety of sources) for PUCs to use as assessment tools.[38] Cyber response assessment criteria and best practices are much less well

[36] The State of New Jersey Board of Public Utilities, (2013) *In the Matter of the Board's Review of the Utilities' Response to Hurricane Irene*, January 23, 2013
[37] Edison Electric Institute, (2013). *Before and after the Storm*,
[38] NARUC, (2014) *Cybersecurity for State Regulators 2.0,* February 2014

developed. Indeed, responding to a cyber attack, for example, could require the cleanup of malware though operations entirely different from typical utility crew restoration operations, and from traditional mutual assistance support. Other non-traditional hazards may also require specialized, supplementary plans for power restoration. For example, the risk of terrorist attacks against crews in a coordinated, Metcalf-style kinetic attack on critical grid components would require security support completely unlike that provided by law enforcement or National Guard personnel in previous events.

B. New Partnerships

State Commissions and companies engaging in risk-oriented assessments of whether (and how much) to prepare for the highest impact events may want to explore how they can leverage the existing efforts and resources of other agencies, entities, and stakeholders. Developing and assessing resilience initiatives for black sky days may require much deeper collaboration with State and Federal emergency management leaders and energy officials, and -- in some cases -- with their counterparts in Canada and Mexico. Of course, these officials have powerful incentives of their own to strengthen collaboration with PUCs and utilities. Utility commissioners can play a decisive role in strengthening preparedness against black sky days; reliability-based investments, prudently chosen, may be able to greatly reduce the overall duration of service interruptions and the threats they pose to public health and safety. But in many states, such collaborative efforts remain limited. Too many "stovepipes of excellence" exist; emergency managers are striving to create increasingly rigorous catastrophic response plans, and PUCs and utilities are making equally strong efforts to strengthen grid resilience against severe hazards, but only rarely are these efforts integrated.

To help States mitigate the risks that extraordinary and hazardous events will pose to their energy systems, the Department of Energy's Office of Electric Delivery and Energy Reliability provides a range of activities to support State and local energy assurance planning and emergency response operations.[39] The National Association of State Energy Officials (NASEO) has also partnered with DOE and NARUC to advance a range of initiatives that can help provide a foundation to build preparedness against extraordinary and hazardous events.[40] Later sections of this report will recommend specific ways that commissioners and their staffs can deepen their collaboration with emergency managers and Federal and State energy officials to advance such efforts.

As Commissioners and utilities deepen their partnerships with State and local emergency managers to prepare against black sky events, the National Response Framework and Emergency Support Function 12 (Energy) provide the crucial starting point to examine how power restoration can become an integrated part of overall disaster response planning and operations.[41]

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[39] Department of Energy, *State and Local Energy Assurance Planning*, at http://energy.gov/oe/services/energy-assurance/emergency-preparedness/state-and-local-energy-assurance-planning.

[40] National Association of State Energy Officials (NASEO) and NARUC, State Energy Assurance Guidelines, December 2009, at http://www.naruc.org/Publications/State_Energy_Assurance_Guidelines_Version_3.1.pdf.

[41] Federal Emergency Management Agency (FEMA), (2013). *National Response Framework: Second Edition*, May 2013; and Federal Emergency Management Agency (FEMA), (2008). *Emergency Support Function #12 – Energy Annex*, January 2008

Section I of this report noted that a growing number of States are developing catastrophic response plans. Those efforts provide especially valuable and timely opportunities for PUCs and utilities to engage with emergency managers. Since black sky events are almost certain to cross state lines, collaborative planning with FEMA Region leaders (and with PUCs and utilities on a regional basis) will also be essential.

Exercises offer another means to strengthen collaboration and better prepare for black sky operations. A prime example of such opportunities is provided by the Central United States Earthquake Consortium's "Capstone 14" exercise in June, 2014. This multi-State exercise will engage local, State and Federal emergency managers with the private sector companies (including utilities and the infrastructure sectors crucial for power restoration) to plan for response and recovery from a catastrophic New Madrid earthquake.[42] As other States and FEMA regions begin to exercise their own evolving catastrophic plans, these events will provide unique opportunities for PUCs and utilities to build working relationships with the officials who will actually lead disaster response operations when an event strikes. Involving PUCs and utilities in these exercises will also help identify shortfalls in existing efforts to integrate power restoration and response planning. Similar benefits might be provided by including commissioners and their staffs in future cyber exercises such as GridEx II, which can highlight the special restoration and resilience problems of wide area, long duration outages caused by SQL injection attacks, advanced persistent threats, and other cyber weapons.

C. Assessing and Managing Black Sky Risks

Many of the most significant threats of black sky events either rarely happen (as in Carrington-level GMD events), or have yet to occur (as in the case of large scale, coordinated cyber attacks on industrial control systems and control center data essential for operating the power grid). If these events do occur, however, their effects would be catastrophic. How can PUCs build an enterprise risk management system to account for black sky days?

Under a risk management system (where risk is assessed in terms of threat, vulnerability, and consequence), the starting point for commissioners and their staffs should be to develop an assessment of the threats that their utilities are most likely to confront. There are a number of possible sources of threat data to build such an assessment. State Energy Assurance Plans -- developed by the State Energy Offices under the umbrella of the National Association of State Energy Officials (NASEO) in partnership with the US Department of Energy (DOE) -- often include data on significant State-specific hazards. In each of the ten Federal Emergency Management (FEMA) regions, FEMA Regional Coordinators and their State and local partners are examining the most likely catastrophic threats to their areas, which will then serve as a basis for catastrophic response planning (including preparedness for the impact of extended power outages on public health and safety). State National Guard Joint Force Headquarters assesses natural and manmade hazards in each State. The Department of Homeland Security supports Fusion Centers in many States that track threat data. The Federal Bureau of Investigations Joint

[42] Central United States Earthquake Consortium's Capstone 14 Exercise, Private Sector Workshop, at http://www.cusec.org/plans-a-programs/capstone14/176

Terrorism Task Forces (JTTFs) may also, in certain circumstances, be able to provide helpful data on manmade threats.

While necessary, however, these assessments of likely threats will fall short of providing reliable predictions of event probability. Risk methodologies for black sky events should therefore take special account of vulnerability and consequence components of the risk equation. Building a risk management framework for extraordinary and hazardous events would also benefit from moving beyond the critical components of the distribution system in question. Given the unique destructiveness of such events, risk assessments should account for the interdependencies that exist with other energy sectors and for the supporting infrastructure on which utilities depend for power restoration.

Once PUCs and commissioners built a shared understanding of criticality, interdependencies and risks of cascading infrastructure failure, the consequences and likelihood associated with various hazard and threat scenarios should be assessed as part of a composite risk profile for both a utility and the greater region it serves. From that profile, alternative mitigation measures could be proposed and evaluated for cost and efficacy. Only by taking such a composite view will it be possible to account for a full range of mitigation options. As joint participants in what should be a common risk management process for catastrophic events, State and local government officials and owners and operators of interdependent infrastructure would likewise benefit from participating in such analysis.

Based on this approach, a risk management process for black sky events would involve three primary components: 1) a comprehensive region-wide assessment of risks to the critical assets identified and their interdependencies, including a detailed assessment current protection measures and response and recovery capabilities; 2) an evaluation of risk mitigation solutions, including cost-benefit analysis to compare the life-cycle cost of identified solutions with their risk reduction potential; and 3) time-based tracking and comparison of region-wide risk, including an evaluation of changes in criticality, threat, and preparedness that would alter the overall risk profile of the utilities within each region.

D. Cost-Benefit Analysis: Issues for Future Consideration

Commissioners already have a set of highly effective assessment tools, including the Interruption Cost Estimate (ICE) Calculator, to help them assess the costs and benefits of proposed investments in resilience. Adapting or supplementing these tools to help commissioners perform cost-benefit analysis for resilience investments will be essential as utilities generate multi-billion dollar proposals over the next few years. Indeed, given the potentially limitless funds that might be spent to minimize or eliminate the risks of outages in catastrophic events, commissioners will have especially strong incentives to develop tools that help them avoid low-payoff investments.

The first step in adapting the ICE Calculator and other metrics for resilience would be to adjust them to accommodate larger-scale events. The Calculator is “not meant to be applied to major outages or blackouts longer than 8 hours.”[43] As with SAIDI, it will likely be necessary to build a complementary formula to accommodate much longer events. In addition, building cost-

[43] Interruption Cost Estimate (ICE) Calculator – BETA, “About the Calculator,” at http://icecalculator.com/

assessment tools focused on extraordinary and hazardous events will also have to account for their enormous, cascading effects and the lost value of service in a long-duration event. Doing so will require analytic initiatives to 1) better estimate the compounding value of lost load over the course of a long-term event; 2) assess the value of lost load form a customer perspective, versus for utilities; 3) differentiate the value of that lost electricity across different types of customers; and 4) account for the difficulty of predicting extraordinary and hazardous events.

The NARUC Resilience Report suggests that the value of electricity is likely to compound over time. If commissioners believe that assessments of value should include the impact of lost load on public health and safety, and on business interruption, this compounding effect will be vastly stronger. Existing econometric models could be adapted to help commissioners estimate the economic damage resulting from the dependencies on electrical power by other critical sectors to include transportation, health services, liquid fuel distribution, communications, and water and wastewater treatment. The cascading effects arising from these cross-sector interdependencies can then be translated into loss of employment and reductions in State GDP that power outages will create as a function of time. It would also be possible to develop more detailed estimates of how public safety hazards will escalate, and develop risk-based decision criteria on how much to invest in reducing event duration.

The NARUC Resilience Report also notes that two different approaches might be taken to conduct cost-benefit analysis. The first is to assess costs of outages to utilities. An alternative would be for PUCs to focus on the value of lost load to customers. Taking that customer-based approach would again tend to increase the costs associated with lost load over time; spoiled food in the refrigerator would quickly become a minor inconvenience compared to the hazards that would emerge in a long-duration outage. Yet, the validity of methodologies to assess the cost of lost load to customers, including the contingent valuation method (which includes measures of willingness of customers to pay to avoid outages) remains a subject of debate.[44]

The scale and scope of economic damage from lost load in a black sky also creates special challenges for assessing costs and determining who should pay for investments to reduce them. John Holdren, the science adviser to President Barack Obama, estimates that a major GMD event could cause $2 trillion dollars in economic losses in the United States in the first year alone, with recovery taking four to ten years.[45] Estimating the potential economic costs of such events in a particular State or service region will pose major challenges. For example, beyond the direct costs of lost load to utility customers, the indirect costs caused by the cascading failures of critical infrastructure and their additional effects on business interruption and disaster response/power restoration costs would be enormous. But who should pay for investments that would benefit society as a whole, when State economies and many thousands of lives are in jeopardy? Should rate-payers bear the full burden? And if utilities prioritize power restoration to certain classes of customers, should those customers pay more for that status? Answering these questions (and the many others that resilience entails) will require new levels of consensus building between commissioners, utilities, and other key stakeholders.

[44] Executive Office of the President, Economic Benefits, pp. 19-20, reviews this debate.
[45] John P. Holdren, "Celestial Storm Warnings," *New York Times*, March 10, 2011.

Predicting the likelihood of extraordinary and hazardous events will also create difficulties for applying familiar cost-benefit methodologies, just as such predictions do for risk assessments. Where at least some historical data exists on severe natural hazards, stochastic modeling may help deal with event uncertainty. Monte Carlo analysis may also be of value in that regard. For manmade events, however, developing more tailored analytic approaches will likely be essential.

## III. SAMPLE RESILIENCE QUESTIONS

State Commissions will need to decide for themselves if they want to explore preparedness against the worst effects of black sky days with companies and other stakeholders. If a Commission decides to explore this issue, this section provides questions that it might ask in informal discussions on overall resilience goals, challenges and priorities. PUC resilience needs and concerns vary, so commissioners will likely need to modify these questions accordingly. Most important: do not ask questions whose answers might create vulnerabilities to cyber or kinetic attack.

### A. Reliability versus Resilience

Utilities in your State may already be developing proposals to invest in resilience, or are likely to do so in the future. In advance of rate cases, asking utility personnel how they define resilience can help set common perspectives on resilience goals and priorities.

1. How does your company integrate resilience into your enterprise risk management structures?

2. What corporate structures and governance drive performance for resilience?

3. What constitutes resilience, and how can we distinguish it from reliability? Is it useful to differentiate them on the basis of the severity of an event (with resilience focused on the most extreme, high consequence hazards)?

4. How might investments in resilience differ from those for reliability? What kinds of projects would fall into which basket?

5. Do you conduct exercises to prepare for severe, non-traditional hazards? How have you adjusted your restoration plans and crew training for severe events?

### B. Extraordinary and Hazardous Threats: Which are of Greatest Concern?

1. Which catastrophic threats does your company see as most probable? What “keeps you up at night?”

2. Have you had discussions with State and local emergency managers, National Guard leaders, or other officials within your State and region on the probability of (and preparedness against) catastrophic hazards, and the challenges these hazards create for power restoration?

3. Have you had discussions with key stakeholders or other critical sectors on the consequence for those sectors of a long-term power outage?

4. In a severe event, natural gas pipelines and other energy infrastructure systems essential for power generation may not only be disrupted by electricity outages, but may themselves be damaged. How do you account for these risks in your restoration planning?

5. In a similar way, the infrastructure that your utility crews need to restore power may be disrupted. Communications systems are a prime example. What measures are you taking to address these challenges for resilience?

C. Deepening Partnerships

1. Have you engaged with the State Energy Office or other State agency on its energy assurance plan?

2. Has your organization engaged with State and Federal emergency management, homeland security, and law-enforcement agencies to plan for "black sky days," and build an integrated approach to power restoration and disaster response and recovery?

D. Specific Challenges for Resilience against Severe Hazards

PUC's will differ in the degree to which they believe it is appropriate or necessary to "get under the hood," and examine the specific power restoration and crisis management issues that could contribute to the duration of an outage. Please adjust these questions to fit your own preferences.

1. Have you engaged in contingency analysis to identify vulnerable assets? If N-1 or N-2 will not be adequate to assess resilience requirements against extraordinary events, what planning factors do you use for these larger-scale events?

2. Have you engaged with the entity responsible for your system's black start capabilities? If you are responsible for this function, do you update and practice the plan for your black start capabilities to get the grid back up and running in an extraordinary event?

3. Utilities are pursuing major improvements in the mutual assistance agreements to help scale up such assistance to deal with regional and national response events. What initiatives are you exploring in this regard?

4. What kinds of facilities and functions do you believe are most urgent for prioritized restoration, and why? To what extent have you shared your actual restoration plans with State officials?

5. If appropriate for your region, to what extent do your contingency plans take into account cross-border capabilities in Canada or Mexico?

6. The Incident Command System (ICS) offers a proven, standardized, and highly effective way to organize infrastructure restoration operations when multiple organizations and agencies must coordinate their efforts (as would certainly be the case in a black sky event). Does your company employ this system? If not, what might be the advantages or potential problems in doing so?

## E. Supplementing Reliability Metrics to Assess Black Sky Resilience Investments

While SAIDI, SAIF, CAIDI, MAIFI, CEMI and other reliability metrics will continue to provide an essential foundation for assessing utility performance, supplementary evaluative tools may also be useful for resilience projects.

1. How should we assess utility resilience against especially severe hazards? How well do SAIDI and her sisters apply to this assessment challenge, and what other metrics might be appropriate?

2. How are risk management tools applied to identifying and prioritizing risk factors such as consequence, likelihood, and vulnerability?

## F. Tools for Assessing Cost-Effectiveness

1. What set of tools is your company using to address cost-benefit analysis for resilience investments? Do you use the ICE calculator, and if so, how can we address its limitations for use regarding long term outages?

2. Do these tools need adaptation to address specific needs faced by your company?

3. In addition to examining the costs of outages from the perspective of utilities, could it also be helpful to assess the value of lost load to customers? How could that best be done? Would that value differ across varying types of customers?

4. What do your key stakeholders believe will be the value of lost load that compounds over time?

5. Do certain types of events carry more weight than others based on an analysis of likelihood and potential consequences? How might those factors be weighted in a cost effectiveness test?

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# Tampa Electric Substation Upgrades

Prepared by K Mara

May 26, 2022

# South Gibsonton Substation 1999 compared to 2002 Expanded bus work to the east


# Skyway Substation 2005 compared 2006
# New control house