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January 15, 2025

VIA E-PORTAL

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

Re: **Docket No. 20250017-EI – Review of 2026-2035 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company.**

Dear Mr. Teitzman:

Attached for filing, please find the Testimony and Exhibit PMC-01 of P. Mark Cutshaw in support of Florida Public Utilities Company's Petition for Approval of 2026-2035 Storm Protection Plan.

Thank you for your assistance with this filing. As always, please don't hesitate to let me know if you have any questions whatsoever.

Sincerely,

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706

MEK

<u>Before the Florida Public Service Commission</u>

Direct Testimony of P. Mark Cutshaw

On Behalf of

<u>Florida Public Utilities Company</u>

<u>Docket 20250017-EI</u>

I. <u>Background</u>

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw. My business address is 780 Amelia Island Parkway, Fernandina Beach, Florida 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

Q. Could you give a brief description of your background and business experience?

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering. My electrical engineering career began with Mississippi Power Company in June 1982. I spent nine years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various locations. I joined FPUC in 1991 as Division Manager in our Northwest Florida Division and have since worked extensively in both the Northwest Florida and Northeast Florida divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues. During January 2024, I moved into my current role as Manager, Electric Operations.

Q. Have you previously testified before the Commission?

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case addressed in Docket No. 20140025-EI, rebuttal testimony in Docket No. 20180061-EI, direct and rebuttal testimony in Docket No. 20190156-EI, which was the limited proceeding to recover storm costs associated with Hurricane Michael, as well as testimony in numerous years for the Fuel and Purchased Power Cost Recovery proceeding. Most recently, I provided testimony in Docket No. 20220049-EI, the initial filing for approval of FPUC's Storm Protection Plan, as well as Dockets Nos. 20220010-EI, 20230010-EI, and Docket No. 20240010-EI for the Storm Protection Plan Cost Recovery Clause proceeding.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview of the 2026 – 2035 Storm Protection Plan ("SPP"), pursuant to Rule 25-6.030, F.A.C. for Florida Public Utilities Company ("FPUC")

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. Attached to my direct testimony is Exhibit PMC-01, which is FPUC's proposed, updated 2026-2035 SPP.

II. Overview of the FPUC SPP

Q. What is the purpose of the FPUC SPP?

A. The purpose of the FPUC SPP is to comply with Florida Public Service Commission Rule 25-6.030 F.A.C., Storm Protection Plan, which was established in accordance with Section 366.96, F.S. Section 366.96, F.S. requires each investor-owned electric utility (IOU) to file a transmission and distribution Storm Protection Plan that covers the immediate 10-year planning period. The plans are required to be filed with the Florida Public Service Commission ("Commission") every three years and 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." s. 366.96(3). The Commission adopted Rule 25-6.030, Florida Administrative Code (F.A.C.), Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Plan Cost Recovery Clause, to implement the new statute.

FPUC filed its first SPP on April 11, 2022, which was approved with modifications by Order No. PSC-2022-0387-FOF-EI, issued in Docket No. 20220049-EI.

FPUC's proposed 2026-2035 SPP is a combination of previously Commission-approved Storm Protection Plan Programs, some of which contain incremental investments, as well as a newly proposed Program across FPUC's Distribution system. To the extent that there are existing programs that are continuations of the Company's legacy Storm Hardening Plan, there are some costs associated with these programs currently included in the base rates approved for the Company during its last rate proceeding. As such, in years past, the Company has identified these costs that are in base rates at the time the Company makes its SPP cost recovery filing, and calculates its costs recovery factors to exclude costs recovered in base rates such that only incremental investments are included for SPPCRC recovery factor as required by Rule 25.6.031, F.A.C.

On August 8, 2024, FPUC filed a petition with the Commission for a rate increase as part of Docket No. 20240099-EI in which among other things, includes a request to remove all Storm Protection Plan costs from base rates and transfer recovery of all SPP programs to the SPPCRC. If approved, all costs associated with currently approved SPP Programs will be recovered through the SPPCRC.

Q. Please describe what was considered in the development of the updated FPUC SPP.

A. FPUC, with the assistance of Pike Engineering, has updated its Storm Protection Plan to ensure that projects undertaken through the Plan will strengthen the utility's electric utility infrastructure to withstand extreme weather conditions. Key aspects of the SPP include the hardening of overhead electrical facilities and the undergrounding of certain electrical distribution lines, which will result in a systematic method of addressing and maintaining ongoing compliance with the requirements of the Rule. This ensures FPUC's implementation of its SPP will achieve the statutory objectives of reducing restoration costs and outage times associated with extreme weather events, while also enhancing reliability.

Q. Were there unique considerations in the initial development of FPUC's SPP?

A. Yes, to a degree, given FPUC's territory and its position as a non-generating utility. While the two FPUC service territories are separated and geographically diverse, FPUC and Pike Engineering analyzed FPUC's historical reliability performance, both during extreme and non-extreme weather conditions. The analysis of the data provided insight into the various drivers (causes) of the outages impacting the FPUC system along with the frequency and relative geographical location.

The resulting, approved FPUC SPP is a combination of previously Commission-approved storm hardening initiatives, some of which contain incremental investments due to program modifications, as well as a newly proposed Program, all of which are grounded on a methodology of resiliency risk scores across FPUC's Distribution system.

Q. Is FPUC proposing significant changes to its updated SPP?

A. No. This plan proposes the continuation of six (6) previously approved SPP Programs and the introduction of a new Program, Distribution Connectivity and Automation. This newly proposed Program reduces outages and their associated restoration times by enhancing the ability to reroute power and by leveraging intelligent grid devices to isolate areas of damage and automatically reroute power from unaffected areas of the grid.

Q. Are there any areas in FPUC's service territory where it has determined, since implementation of its 2022 Plan, that SPP projects are not feasible or practical?

A. No. Though implementation strategies may differ between projects due to geographical or other concerns, all currently approved and proposed SPP Programs are feasible and practical across FPUC's entire service territory. Some of these project-to-project variations may include combining multiple Programs within a single project in order to achieve the statutory objectives.

Q. Please provide a description of what programs are included in the updated FPUC SPP?

A. This updated plan proposes the continuation of six (6) previously approved SPP Programs and the introduction of a new Program, Distribution Connectivity and Automation. These programs include:

Overhead Feeder Hardening

The Overhead Feeder Hardening program upgrades backbone overhead lines to extreme winds requirements outlined in the National Electric Safety Code ("NESC").

Overhead Lateral Hardening

Like the Overhead Feeder Hardening program, the Overhead Lateral Hardening program upgrades existing overhead facilities along key lateral lines off the feeder to withstand extreme wind requirements outlined in the NESC.

Overhead Lateral Undergrounding

The Overhead Lateral Undergrounding program addresses undergrounding laterals in place or the relocation and undergrounding of these overhead electric facilities.

Distribution Pole Inspections and Replacements

This Distribution Pole Inspections and Replacements Program will continue the eight-year wood pole inspection and replacement of poles that do not meet NESC strength requirements.

Transmission System Inspection and Hardening

This Transmission System Inspection and Hardening Program will continue transmission inspections on all transmission facilities and replacement of the remaining transmission wood poles with concrete poles.

Transmission & Distribution Vegetation Management Program

The Transmission & Distribution Vegetation Management Program will continue to address vegetation management activities related to FPUC transmission and distribution lines under a the currently approved 4-year trim cycle.

Distribution Connectivity and Automation Program

The Distribution Connectivity and Automation Program proposes improvements to the topology of the Distribution system that will facilitate reduced outage times through the addition of feeder ties as well as intelligent protection and automation equipment.

Q. Please describe the benefits associated with the FPUC SPP.

A. The major benefit of the FPUC SPP is to provide increased resiliency and faster restoration times to the FPUC customers. Although the total number of customers served by FPUC is relatively small in comparison to other utilities, our customers nonetheless rely on FPUC to provide safe and reliable electric service which is essential to the life, health, and safety of the public, and has become a critical component of modern life. Both divisions of FPUC's service territory are notably hurricane-prone given that the Northeast Division consists of Amelia Island and as confirmed by the impact of Hurricane Michael on our Northwest Division in 2018. As such, FPUC's SPP reflects a robust storm protection plan, which is critical to maintaining and improving grid resiliency and storm restoration as contemplated by the Legislature in Section 366.96 F.S.

FPUC's SPP programs will provide increased infrastructure resiliency, reduced restoration time, and reduced restoration cost should FPUC be impacted by hurricanes or other extreme weather events.

Q. Has FPUC changed the evaluation or prioritization of any of the projects under its proposed Plan from its 2022 Plan?

A. The Risk Resiliency Model has been updated to take into consideration the age of the distribution feeders as well as historical districts. In addition, model inputs were updated to reflect current system characteristics. The lateral undergrounding criteria was also adjusted to better reflect expected benefits resulting in a reduction of proposed undergrounding projects over the life of the Program. Finally, the divisions have been separated and examined independently from one another allowing for more efficient mobilization of resources.

Q. How did FPUC determine the prioritization for the projects under this proposed, updated SPP?

A. FPUC's utilizes the Risk Resiliency Model which leverages data inputs from various sources to evaluate and risk rank scenarios based on a balance of Probability, Response, and Impact. Projects representing the highest risk among the analyzed scenarios are represented with a higher risk resiliency score and are prioritized over projects with lower risk resiliency scores. It is important to note that the prioritization process described does not account for other factors that may influence FPUC's decision regarding the order of execution of these projects such as the availability of resources or material.

III. <u>Storm Protection Plan Programs</u>

Q. What information is provided for each program in the FPUC SPP?

A. The information provided, consistent with Rule 25-6.030(3) (d), F.S., is as follows:

- A description of how each program is designed to enhance FPUC's existing transmission and distribution facilities including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions;
- Identification of the actual or estimated start and completion dates of the program;
- A cost estimate including capital and operating expenses;
- A comparison of the costs and the benefits; and
- A description of the criteria used to select and prioritize proposed storm protection programs.

Each of the above-listed descriptions is provided in Section 3.0 of FPUC's SPP.

Q. Please describe the Overhead Feeder Hardening Program?

A. The Overhead Feeder Hardening program will upgrade backbone overhead lines to extreme winds requirements outlined in the NESC. The backbone of a feeder resembles the major arteries of the distribution circuit that services a particular community. When a fault occurs on a backbone of the feeder, upwards of 2,500 customers can be immediately impacted.

Q. Please describe the Overhead Lateral Hardening Program.

A. Like the Overhead Feeder Hardening program, the Overhead Lateral Hardening program will upgrade existing overhead facilities along key lateral lines off the feeder to withstand extreme wind requirements outlined in the NESC. Laterals are separately protected sections of the feeder providing service to upwards of 200 to 300 customers.

Q. Please describe the Overhead Lateral Undergrounding Program.

A. The Overhead Lateral Undergrounding program will address undergrounding overhead laterals in place or the relocation and undergrounding of these overhead electric facilities, many of which are located in heavily vegetated areas, environmentally sensitive areas, or in areas where upgrading the overhead construction to NESC extreme wind standards is not practical or consistent with industry design standards. The program is also proposed to include the undergrounding of overhead facilities crossing major thoroughfares (I-10, A1-A, and SR-200). Undergrounding primary and secondary overhead facilities reduces obstructions to roadways that are essential for providing access to restoration crews and other emergency response personnel, thus accelerating power restoration and community access to these vital resources.

Q. Please describe the Distribution Pole Inspection and Replacement Program as included in the FPUC SPP.

A. This Distribution Pole Inspection and Replacement program will continue the eight-year wood pole inspection program currently in place. Should a pole fail the inspection process, it will be scheduled to be replaced. The most current edition of the NESC serves as a basis for the design of replacement poles for wood poles that fail inspection. Grade 'B' construction, as described in Section 24 of the NESC, has been adopted as the standard of construction for designing new pole installations and the replacement of reject poles. Also, extreme wind loading, as specified in rule 250C and figure 250-2(a) of the NESC, has been adopted.

Q. Please describe the Distribution Connectivity and Automation Program as included in the FPUC SPP.

A. The Distribution Connectivity and Automation Program proposes improvements to the topology of the Distribution system that will facilitate reduced outage times through the addition of feeder ties as well as intelligent protection and automation equipment. Additional feeder ties reduce outage times by providing alternates feeds, facilitating the rerouting of power to unaffected areas of the grid. Combined with intelligent devices, these feeder ties can be used to mitigate outages to unaffected areas of the grid.

Q. Please describe the Transmission System Inspection and Hardening Program as included in the FPUC SPP.

A. The Transmission System Inspection and Hardening program will continue transmission inspections on all transmission facilities which includes patrols of the 138 KV and 69 KV transmission lines owned by FPUC. This inspection ensures that all structures have a detailed inspection performed at a minimum of every six years. In addition to the six-year inspections mentioned above, wood transmission poles are also included in the 8-year distribution wood pole ground-line condition inspection and treatment program. Should a wood transmission pole be identified during the inspection as not meeting the minimum strength requirements, this pole will be replaced with a concrete pole that meets the current NESC codes and extreme wind loading standards. The Transmission Wood Pole Replacement program accelerates the full replacement of existing wood poles on FPUC's 69kV system with concrete poles proven more resilient to extreme weather conditions. Transmission substation equipment will also be inspected annually to document the integrity of the facility and identify any deficiencies that require action.

Q. Please describe the Transmission & Distribution Vegetation Management Program

A. This Transmission & Distribution Vegetation Management program continues the approved four-year vegetation management cycle on the transmission lines and distribution main feeders and laterals on the system. FPUC completed a study regarding its vegetation management cycle and has determined that this four-year cycle is an efficient and cost-effective trim cycle that will reduce outages and restoration times during extreme weather events.

Q. Will there be any internal staffing changes that will result from the development and administration of the FPUC SPP reflected in this filing?

A. No. There will be no additional internal staffing changes as a result of the proposed, updated FPUC SPP.

IV. <u>Details for the Storm Protection Plan First Three Years</u>

Q. What information has been provided for the initial three-year period of the FPUC SPP?

A. The information required by Rule 25-6.030(3)(e)(1), F.A.C., for the first year (2026) of the updated FPUC SPP is provided in Sections 3.0, 5.0 and 6.0 of FPUC's SPP as follows:

- The actual or estimated construction start date and completion dates;
- A description of the affected existing facilities, including number and type(s) of customers served, historic service reliability performance during extreme weather conditions, and how this data was used to prioritize the proposed storm protection project;
- Cost estimates, including capital and operating expenses, along with a description of the criteria used to select and prioritize proposed projects is included in the description of each proposed FPUC SPP program provided in Section 6.0 of the FPUC SPP.

For the second and third years, the following information has been provided.

- The estimated number and costs of projects under each specific SPP program;
- Information used to develop the estimated rate impacts.

This information is provided in Section 3.0 through Section 3.8 of FPUC's SPP.

Q. What vegetation management information is provided for the initial three-year period of the FPUC SPP?

A. Information required by Rule 25-6.030(3)(f), F.A.C., for the first three years of the vegetation management activities under the updated FPUC SPP is provided in Sections 1.3 and 3.8 of FPUC's SPP and additional information included in Appendix C to FPUC's SPP. Included are the projected trim frequency, the projected trim miles of transmission and distribution overhead facilities, and the estimated annual labor and equipment costs for both utility and contractor personnel. Also included are descriptions of how the vegetation management activities will reduce outage times and restoration costs due to extreme weather conditions in Sections 1.3 and 3.8 and Appendix C of FPUC's SPP.

Q. Are the jurisdictional revenue requirements for the 2026 – 2035 period included in the SPP?

A. Yes. This information regarding the estimated jurisdictional revenue requirement is included in Section 4.0 of the SPP. This estimate is based on the proposed SPP programs and current operating environment.

Q. Is information provided in the SPP that shows the estimated rate impact detail?

A. Yes. This information regarding the estimated rate impact detail is included in Section 5.0 of the FPUC SPP. This estimate is based on the proposed SPP programs and the current economic and operating environment. The cost recovery filing for FPUC's expenditures under its currently approved SPP, as well as projected costs associated with the updated SPP, will continue to be submitted for approval of cost recovery in Docket No. 20250010-EI. Again, as noted above, FPUC has filed a petition with the Commission for a rate increase as part of Docket No. 20240099-EI, which includes a request to remove SPP-related costs from base rates and to transfer recovery of all costs associated with approved SPP programs to the SPPCRC. If approved, all costs associated with SPP Programs currently recovered through base rates, such as Transmission & Distribution Vegetation Management, Distribution Pole Inspections and Replacements and Transmission System Inspection and Hardening programs will be transferred to the SPPCRC for recovery, which will reduce upward pressure on base rates, but will inflate the SPPCRC factor.

Q. Are there any implementation alternatives that could mitigate the rate impact?

A. FPUC has not identified any implementation alternatives that could mitigate the resulting rate impact of the proposed SPP. FPUC's proposed 2026-2035 SPP is a combination of previously Commission-approved Storm Protection Plan Programs, some of which contain incremental investments, as well as a newly proposed Program across FPUC's Distribution system. Alternate implementation plan(s) beyond what is proposed in the SPP would delay the realization of benefits, and thus result in higher storm restoration costs associated with extreme weather events. As part of the currently approved plan, FPUC implemented a methodical ramp up of investments during the first three years of the SPP of which, in addition to other benefits, this methodical ramp up of investments mitigated the resulting rate impact in the first three years of the plan and allows for the Hurricane Michael cost recovery surcharge to expire.

Q. What benefits does the Company anticipate will result from implementation of its updated SPP?

A. Implementation of FPUC's updated SPP will result in a reduction of storm restoration costs and increase in service reliability; associated with a reduction in outage events during both extreme and non-extreme weather conditions.

V. <u>Conclusion</u>

Q. Does FPUC anticipate that the SPP will meet all the legislative requirements of Section 366.96, F.S. and FPSC Rule 25-6030, F.A.C.?

A. Yes. The FPUC SPP and the information contained does comply with all the legislative requirements contained within Section 366.96, F.S. and Rule 25-6.030, F.A.C.

Q. Based on the details of the SPP, does FPUC anticipate a continued reduction in outages and restoration cost associated with extreme weather events?

A. Yes. The SPP contains a number of programs that will enhance the resiliency of FPUC's electric distribution and transmission infrastructure. The previously approved SPP builds on what had already been accomplished through the Storm Hardening Plan and enhances those efforts through additional programs that will further enhance the reliability and resiliency of FPUC's electric system in a cost-effective manner. This SPP is largely a continuation of FPUC's previously approved plan and also contemplates an additional program that will further reduce the Company's response and outage times when events do occur.

Q. Does this conclude your testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by Electronic Mail to the following parties of record this 15th day of January, 2025:

Carlos Marquez Jennifer Augsperger Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850 cmarquez@psc.state.fl.us jaugspur@psc.state.fl.us discovery-gcl@psc.state.fl.us
Walt Trierweiler/P. Christensen / Charles Rehwinkel/Mary Wessling/Octavio Ponce/Austin Watrous Office of Public Counsel c/o The Florida Legislature 111 W. Madison Street, Room 812 Tallahassee, FL 32399-1400 Trierweiler.Walt@leg.state.fl.us Wessling.Mary@leg.state.fl.us Rehwinkel.Charles@leg.state.fl.us Christensen.patty@leg.state.fl.us Ponce.octavio@leg.state.fl.us Watrous.austin@leg.state.fl.us

By: ______________________
Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
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EXHIBIT PMC-01

FPUC Storm Protection Plan

2026-2035

Florida Public Utilities Company

Storm Protection Plan 2026 - 2035

Rule 25-6.030, F.A.C.

January 15, 2025

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EXECUTIVE SUMMARY

In 2019, the Florida Legislature passed Senate Bill 796 to enact Section 366.96, Florida Statutes (F.S.), entitled "Storm Protection Plan Cost Recovery." Section 366.96, F.S. requires each investor-owned electric utility (IOU) to file a transmission and distribution Storm Protection Plan (SPP) that covers the immediate 10-year planning period. The plans are required to be filed with the Florida Public Service Commission ("Commission") every three years and 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." The Commission adopted Rule 25-6.030, Florida Administrative Code (F.A.C.), Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Plan Cost Recovery Clause, to implement the new statute[1]. The Rules became effective February 18, 2020, with the first filing from the utilities required by April 10, 2020.

On April 10, 2020, Florida Public Utilities Company (FPUC) filed a Motion requesting to defer filing of its SPP and refrain from participating in the Storm Protection Plan Cost Recovery Clause ("SPPCRC") proceeding due to circumstances affecting the utility as a result of Hurricane Michael. By Order No. PSC-2020-0097-PCO-EI, issued in Docket No. 20200068-EI, the prehearing officer granted that motion and FPUC was authorized to file its SPP in April 2021 with the next update then due in April 2023 in order to sync FPUC's next filing with those of the other Florida investor-owned utilities ("IOUs"). Thereafter, the other Florida IOUs entered in settlement agreements for their respective initial SPPs. Within those settlement agreements, the parties agreed that the other IOUs would file their next SPP in April 2022. In light of the fact that the new date for filing by the other IOUs would now have FPUC out of sync again in terms of its filings, the Company asked the Commission to allow FPUC to defer its filing an additional year, which would align FPUC on the same schedule with the other Florida IOUs. That request was granted by Order PSC-2020-0502-PAA. Thus, consistent with that Order, FPUC continued to operate under its legacy Storm Hardening Plan until the next scheduled SPP filing in April of 2022.[2] FPUC filed its first SPP on April 11, 2022, which was approved with modifications by Order No. PSC-2022-0387-FOF-EI, issued in Docket No. 20220049-EI[3]. The Office of Public Counsel filed an appeal to the Florida Supreme Court, which upheld the Commission's decisions as it related to each of the investor-owned utilities by an opinion issued November 14, 2024.[4]

Since then, FPUC, with the assistance of Pike Engineering, has updated a Storm Protection Plan to ensure that projects undertaken through the Plan will strengthen the electric utility's infrastructure to withstand extreme weather conditions. Key aspects of the SPP include the hardening of overhead electrical facilities and the undergrounding of certain electrical distribution lines, which will result in a systematic method of addressing and maintaining ongoing compliance with the requirements of the Rule. This ensures FPUC's

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[1] *Docket No. 20190131-EU, In re: Proposed adoption of Rule 25-6.030, F.A.C., Storm Protection Plan and Rule 25-6.031,F.A.C.,Storm Protection Plan Cost Recovery Clause.*

[2] *Docket No. 20200068-EI, In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company.*

3 Docket No. 20220049-EI, In re: Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company

[4] Opinion issued in the following, consolidated proceedings: Nos. SC2022-1733, SC2022-1735, SC2022-1745, SC2022-1748, & SC2022-1777

implementation of its SPP will achieve the statutory objectives of reducing restoration costs and outage times associated with extreme weather events, while also enhancing reliability.

FPUC's proposed 2026-2035 SPP is a combination of previously Commission-approved Storm Protection Plan Programs, some of which contain incremental investments, as well as a newly proposed Program across FPUC's Distribution system. To the extent that there are existing programs that are continuations of the Company's legacy Storm Hardening Plan, there are some costs associated with these programs currently included in the base rates approved for the Company during its last rate proceeding. As such, in years past, the Company has identified these costs that are in base rates at the time the Company makes its SPP cost recovery filing, and calculates its costs recovery factors to exclude costs recovered in base rates such that only incremental investments are included for SPPCRC recovery factor as required by Rule 25.6.031, F.A.C. On August 8, 2024, FPUC filed a petition with the Commission for a rate increase as part of Docket No. 20240099-EI in which among other things, includes a request to remove all Storm Protection Plan costs from base rates and transfer recovery of all SPP Programs to the SPPCRC. If approved, all costs associated with currently approved SPP Programs will be recovered through the SPPCRC[5].

SPP Programs

It is practically and prudently impossible to eliminate all outages associated with extreme weather conditions. However, programs can be implemented to significantly reduce outages and ancillary impact. This report outlines descriptions, prioritization, costs, and benefits for the following SPP programs:

- Overhead Feeder Hardening
- Overhead Lateral Hardening
- Overhead Lateral Undergrounding
- Distribution Connectivity and Automation
- Distribution Pole Inspections and Replacements
- Transmission System Inspection and Hardening
- Transmission & Distribution Vegetation Management

The plan represents the next 10-year investment in strengthening the utility infrastructure and is not intended to represent the total investment or implementation horizon to completely strengthen FPUC's distribution system. While some programs will be completed ahead of others due to criticality of impact and lower volume (e.g., Transmission System Inspection and Hardening), most will span beyond the ten-year planning period due to the complexities in the design and construction of the project, as well as the sheer volume of infrastructure to strengthen.

This plan proposes the continuation of six (6) previously approved SPP Programs and the introduction of a new Program, Distribution Connectivity and Automation. This newly proposed Program reduces outages

[5] Section 3.4 of this report proposes a new SPP program, part of which is included in FPUC's current rate increase petition. If both are approved, FPUC would continue to account for base rate recovery at the time of SPPCRC.

and their associated restoration times by enhancing the ability to reroute power and by leveraging intelligent grid devices to isolate areas of damage and automatically reroute power from unaffected areas of the grid.

FPUC recognizes that the holistic strengthening of an electric utility grid and a utility's preparation for extreme weather events spans beyond the programs mentioned above and subsequently included in this report. There are other aspects of a holistic plan which include efforts of which FPUC has undertaken for years and carry forward in parallel to this plan up until which time they are transferred to the SPP. These initiatives include things such as coordination with local government officials, re-evaluation of construction standards against new standards that may emerge, partnering with Joint Use facility owners, and others.

Finally, FPUC has removed SPP Program Management from this list of approved Programs. This is a Full Time Equivalent (FTE) position that is responsible for continued development, monitoring and administration of FPUC's SPP. This position is responsible for the SPP projects, scheduling, and cost control/data collection necessary for the success of the overall SPP as well as documentation necessary for cost recovery. While the function of this position is not going away, the costs associated with it have been included within the projections of each of the proposed Programs noted above.

INVESTMENT PLAN

FPUC recognizes the complexities of implementing new programs, the importance of identifying potential pitfalls early, and the validation of initial assumptions. With this in mind, the initial FPUC SPP ten-year investment plan included a methodical ramp up of investments that allowed for the acquisition of resources, initiation of design activities, the refinement of projects, and the Hurricane Michael cost recovery surcharge to expire[6]. This SPP plan proposes $257.7M in Capital Investments and O&M Expenditures over the ten-year planning horizon utilizing a levelized annual investment and expenditure profile. Figure 1 below shows the proposed SPP investment plan which includes $20.1M in newly proposed Distribution SPP program, $193.4M in the three previously approved Distribution Hardening Programs, and $44.2M in legacy Storm Hardening activities approved as part of FPUC's current SPP plan (T&D Vegetation Management, Distribution Pole Inspections and Replacements, and Transmission System Inspection and Hardening activities). Figure 2 below, details the breakdown by Program type for the $74.8M in the first three years of the plan within the approximately $257.7M SPP 10-year investment.

[6] http://www.floridapsc.com/library/filings/2020/11003-2020/11003-2020.pdf

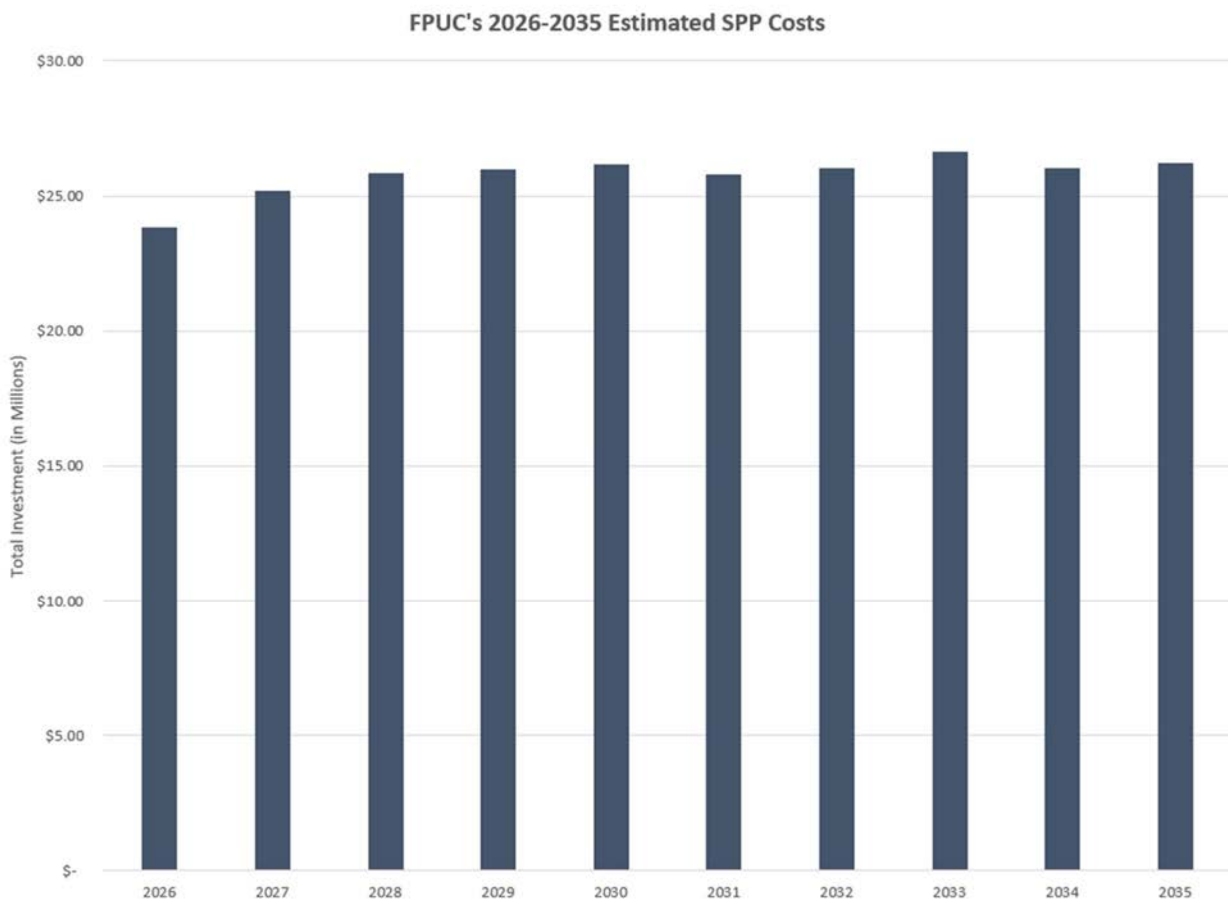


Figure 1 – Ten-year estimated investment profile for SPP Programs

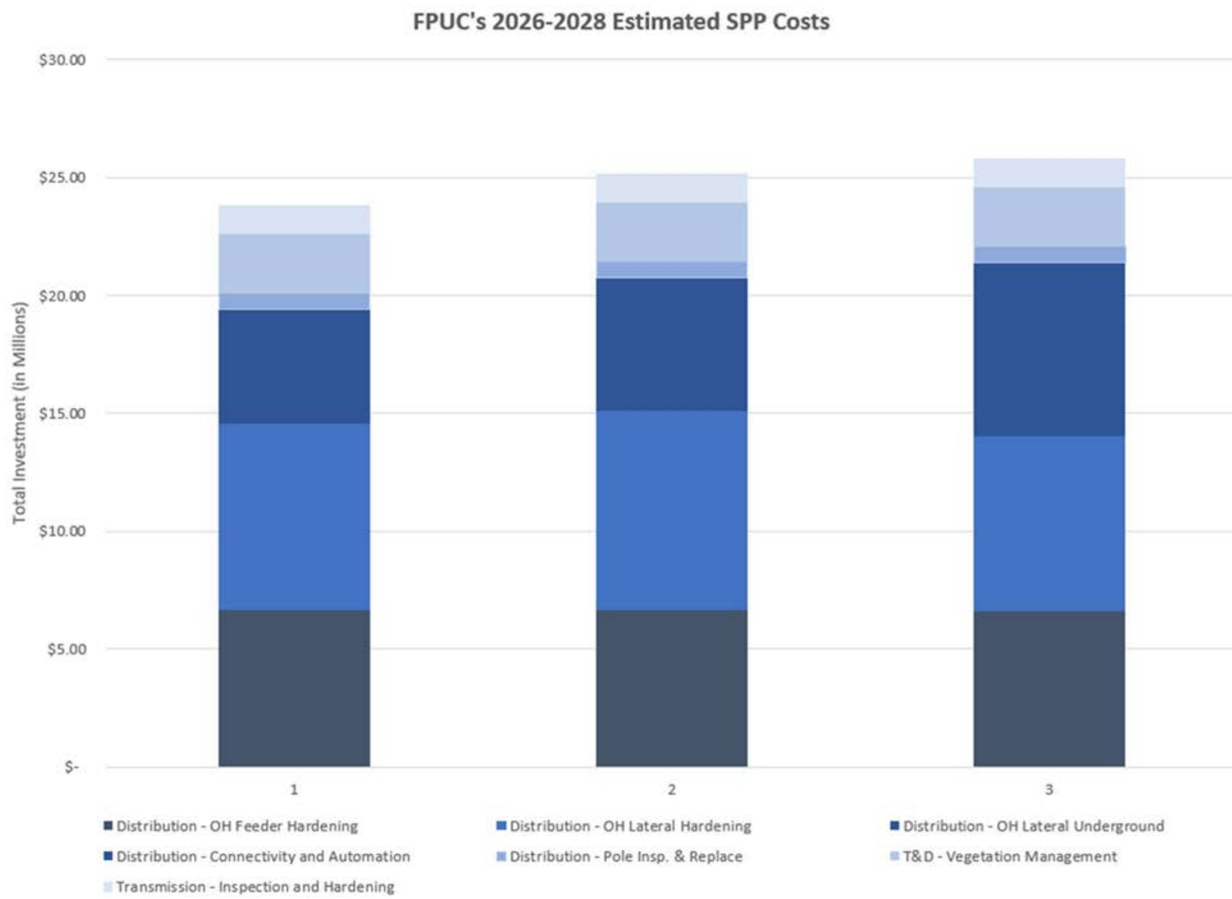


Figure 2 - Three-year estimated investment profile for SPP Programs

1.0 INTRODUCTION

Following the historical 2018 hurricane season, which brought Hurricane Michael and its devastating impact to the Florida Panhandle communities, the Florida Legislature passed Senate Bill 796 finding that "it is in the State's interest to strengthen electric utility infrastructure to withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management." Further the Florida Legislature found that "protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability to customers."

Florida Public Utilities Company (FPUC), with the assistance of Pike Engineering, undertook the development of a Storm Protection Plan that would align with the Legislature's findings in Section 366.96, Florida Statutes, as well as the Commission's implementing Rule, and developed a SPP that promotes the overhead hardening of electrical facilities and the undergrounding of certain electrical distribution lines resulting in a systematic method of addressing and maintaining ongoing compliance with the requirements of the Rule, which will ensure FPUC's implementation of its SPP achieves the statutory objectives of reducing restoration costs and outage times associated with extreme weather events, while also enhancing reliability.

1.1 BACKGROUND

The propensity of hurricanes to come near or impact the State of Florida is not uncommon. The National Oceanographic and Atmospheric Administration (NOAA) has recorded 414 Tropical events (from Extratropical Storms to Category 5 hurricanes) coming within 60 nautical miles of the Florida coast in their historical archives through 2023; 58 of which within the last 20 years (Figure 3). While most of these storms had isolated and scattered impact to Florida communities or more specifically the electric utility infrastructure within those communities, others such as Hurricanes Charley, Wilma, and Irma, or more recently Michael, Ian, and Idalia have left a much deeper impact in the wake of their path.

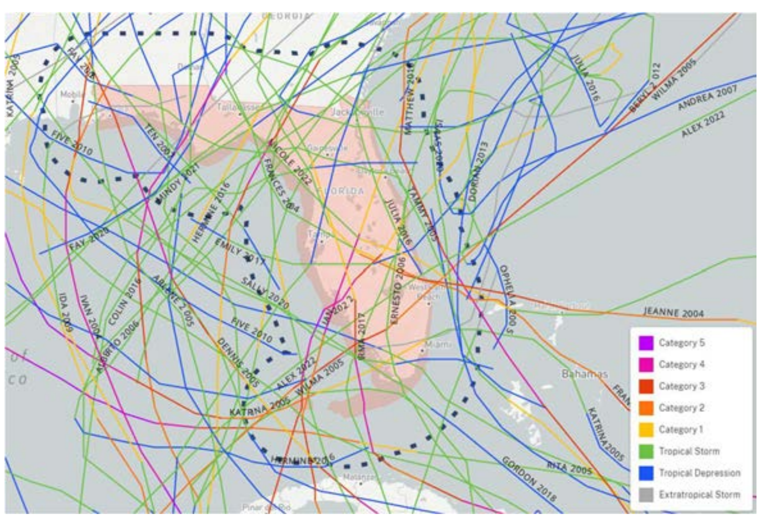


Figure 3 - Florida 20-year tropical event path

FPUC provides electric utility service to two distinct and non-contiguous areas of Florida; the geographical location of which, outside of Hurricane Michael in 2018, has isolated the FPUC territory from the direct path of a Category 1 or stronger weather event (Figure 4 and Figure 5). Nonetheless, the path of a hurricane is unpredictable and preparations ahead of hurricane season and when a potential threat looms in the Atlantic Ocean or the Gulf of Mexico, are essential in ensuring the continued electric service reliability when customers need it most. Although Hurricane Michael is the only notable direct impact to FPUC territory in recent history, both divisions have been impacted by bands or tornadoes spawned by the outer bands of nearby hurricanes, most recently Hurricane Helene in 2024. For this reason, prudent and necessary investments must be made to strengthen the resiliency of the electric grid and reduce storm restoration costs associated with either the planning for potential impact or the recovery from it.

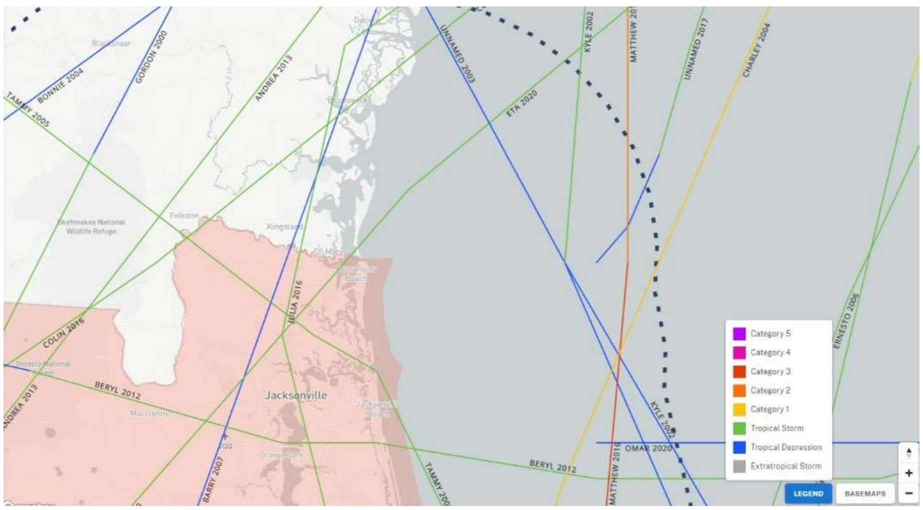


Figure 4 - Northeast Florida 20-year tropical event path

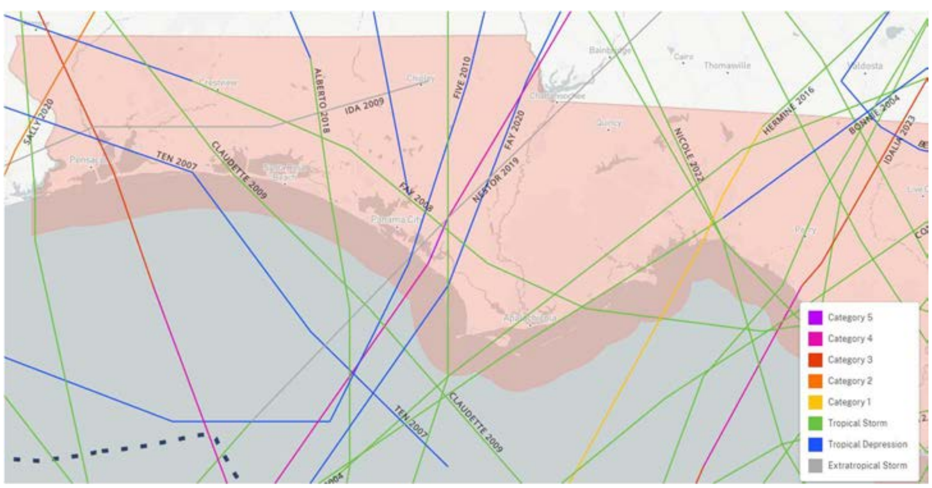


Figure 5 - Northwest Florida 20-year tropical event path

As mentioned above, FPUC has two distinct electric divisions that are not physically connected at the distribution level. The Northwest (NW) Division, also referred to as Marianna, and the Northeast (NE) Division, also referred to as Fernandina Beach are approximately 250 miles apart (Figure 6).

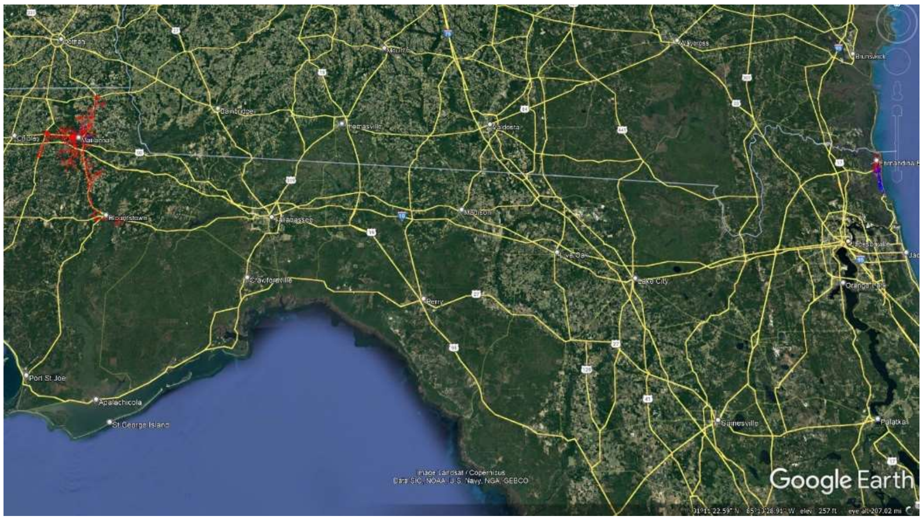


Figure 6 - FPUC separation of service areas

Due to their separation, the geographical location, and the architectural influences of their surrounding communities, the two divisions differ in their electrical characteristics. The NE division, located in Amelia Island in the North easternmost part of the State, serves approximately 17,000 customers. Approximately 60% of the distribution system in this division is of underground (UG) construction with the majority of the overhead facilities located along the northwestern part of the island (Figure 7).

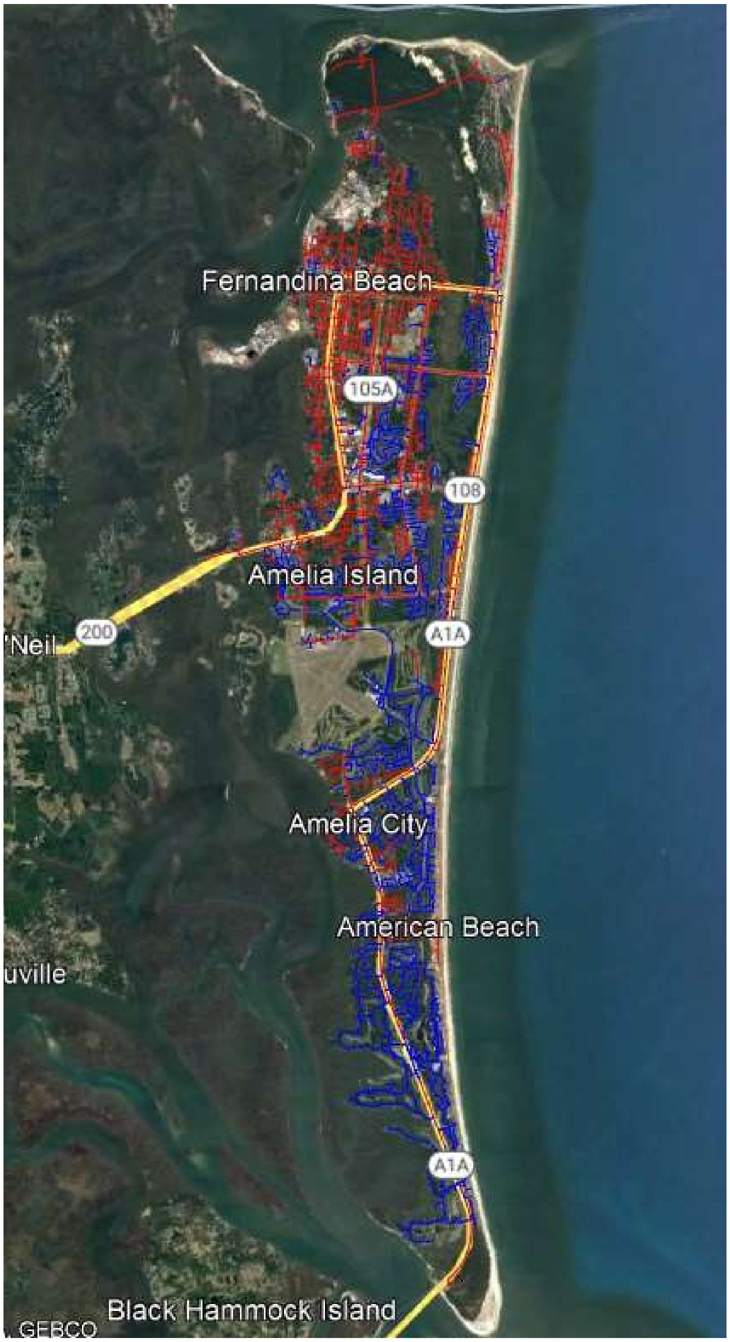


Figure 7 - FPUC NE Division service area

The NW division serves approximately 12,000 customers in parts of Jackson, Calhoun, and Liberty counties along the Florida panhandle. Approximately 94% of the distribution system in this division is of overhead (OH) construction with the majority of the UG facilities located along isolated neighborhoods or certain commercial establishments (Figure 8). FPUC does not own nor operate any Transmission facilities in this Division[7], however, FPUC is in active discussions with Florida Power and Light (FPL) regarding the sale and transfer of certain Transmission and Substation assets in this division.

[7] FPUC receives service from FPL at a distribution voltage at six separate interconnection points.

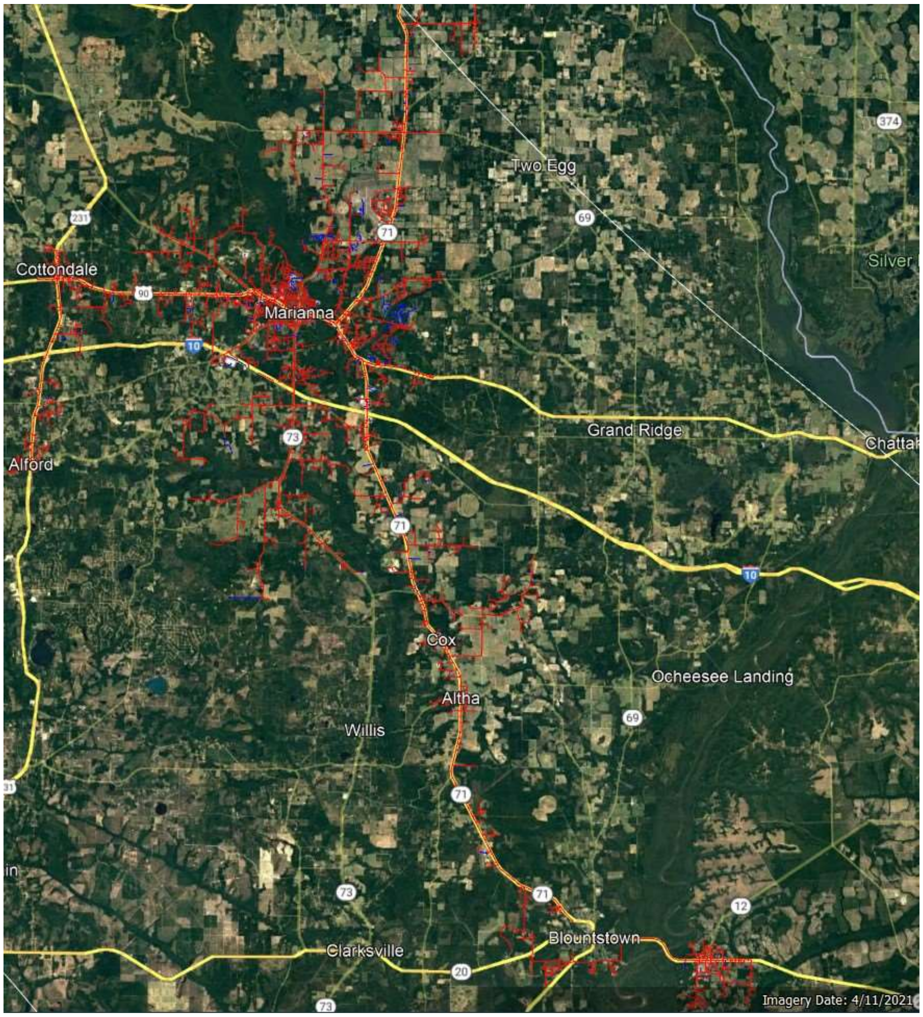


Figure 8 - FPUC NW Division service area

As a result of the differences in their electrical characteristics, the strategy, method, and tactics (Programs) that are required to strengthen the electric grid differ. These differences will drive year to year variances in investment allocation, project selections, and ultimately construction completion.

1.2 Program Development

FPUC and Pike Engineering analyzed the Company's historical reliability performance, both during extreme and non-extreme weather conditions. The analysis of the data provided both parties with insight into the various drivers (causes) of the outages impacting the FPUC system along with the frequency and relative geographical location.

FPUC Staff, in collaboration with Pike Engineering, leveraged this information to continue the development of the Overhead Feeder Hardening, Overhead Lateral Hardening, and Overhead Lateral Undergrounding Programs to address the requirements of the FPSC Rule and thus reduce storm restoration costs associated with extreme weather events and improve the overall service reliability for customers. All distribution areas of the FPUC system were analyzed and determined to be able to benefit from one or more of these programs.

- Overhead Feeder Hardening
    - The Overhead Feeder Hardening program upgrades backbone overhead lines to extreme winds requirements outlined in the National Electric Safety Code (NESC)[8]. The backbone of a feeder resembles the major arteries of the distribution circuit that services a particular community. When a fault occurs on a backbone, upwards of 2,500 customers can be immediately impacted.

- Overhead Lateral Hardening
    - Like the Overhead Feeder Hardening program, the Overhead Lateral Hardening program upgrades existing overhead facilities along key lateral lines off the feeder to withstand extreme wind requirements outlined in the NESC. Laterals are separately protected sections of the feeder providing service to upwards of 200 to 300 customers.

- Overhead Lateral Undergrounding
    - The Overhead Lateral Undergrounding program addresses undergrounding laterals in place or the relocation and undergrounding of these overhead electric facilities, many of which are in heavily vegetated areas, environmentally sensitive areas, or in areas where upgrading the overhead construction to NESC extreme wind standards is not practical or consistent with industry design standards.
    - FPUC proposes expanding the Overhead Lateral Undergrounding Program to include overhead road crossings for major thoroughfares (I-10, A1-A, and SR-200) within its service territory. Undergrounding primary and secondary overhead facilities reduces obstructions to roadways that are essential for providing access to restoration crews and other emergency response personnel, thus accelerating power restoration and community access to these vital resources.

Additionally, FPUC and Pike Engineering, analyzed areas within FPUC's distribution system that would benefit from additional feeder ties and protection equipment to support automated restoration during extreme weather events.

- Distribution Connectivity and Automation
    - The Distribution Connectivity and Automation Program proposes improvements to the topology of the Distribution system that will facilitate reduced outage times through the addition of feeder ties as well as intelligent protection and automation equipment. Additional feeder ties reduce outage times by providing alternates feeds, facilitating the rerouting of power to unaffected areas of the grid. Combined with intelligent devices, these feeder ties can be used to mitigate outages to unaffected areas of the grid.

[8] For all designs, FPUC leverages the most current version of the NESC in place - currently C2-2023.

Finally, FPUC proposes continued investments in certain Legacy programs previously proven to improve overall system resiliency during extreme weather events.

- Distribution Pole Inspections & Replacements
    - The Distribution Pole Inspection & Replacement program targets the replacement of wood Distribution poles that have been identified for replacement following their cyclical inspection. Depending on the location of the pole, a failure on it could have an impact anywhere from a single customer to upwards of 2,500 customers.

- Transmission System Inspection and Hardening
    - The Transmission System Inspection and Hardening consolidated the legacy Six Year Transmission Structure Inspection Program and the Storm Hardening of Existing Transmission Structures. The program proposes to complete the full replacement of existing wood poles on FPUC's 69kV system with concrete within this planning period. Outages to Transmission lines have the potential to impact thousands of customers at a time and prolong the restoration time during extreme weather events.

- Transmission & Distribution Vegetation Management
    - Continuation of the 4-year trim cycle for Transmission & Distribution overhead lines. The majority of outages on overhead systems are the result of falling vegetation. This program minimizes the impact of such vegetation from within the utility's right of way.

These Programs are discussed in detail in section 3 of this report.

1.3 Investment Plan

FPUC's 10-year SPP investment is a $257.7M recommendation that includes a mix of previously approved and new programs targeting Distribution construction types and standards and legacy programs that target the strength and condition of Transmission and Distribution assets.

The breakdown of investments across these three classes is shown below:

- **New SPP Programs - $20.1M**
    - *Distribution Connectivity and Automation*

- **Legacy Programs - $237.6M**
    - *Overhead Feeder Hardening*
    - *Overhead Lateral Hardening*
    - *Overhead Lateral Undergrounding*
    - *Distribution Wood Pole Inspections and Replacement*
    - *Transmission & Distribution Vegetation Management*
    - *Transmission System Inspection and Hardening*

FPUC's proposed 10-year estimated investment plan is shown in Figure 9 below and outlines a levelized annual investments over the next ten-year planning horizon. This investment recommendation ensures the continued execution of currently approved SPP Programs at a pace that is commensurate with the cruciality of improvements, the impact to Customer rates, and the Company's execution capacity. A detailed breakdown for the first three years of the plan is subsequently shown in Figure 10 and Table 1.

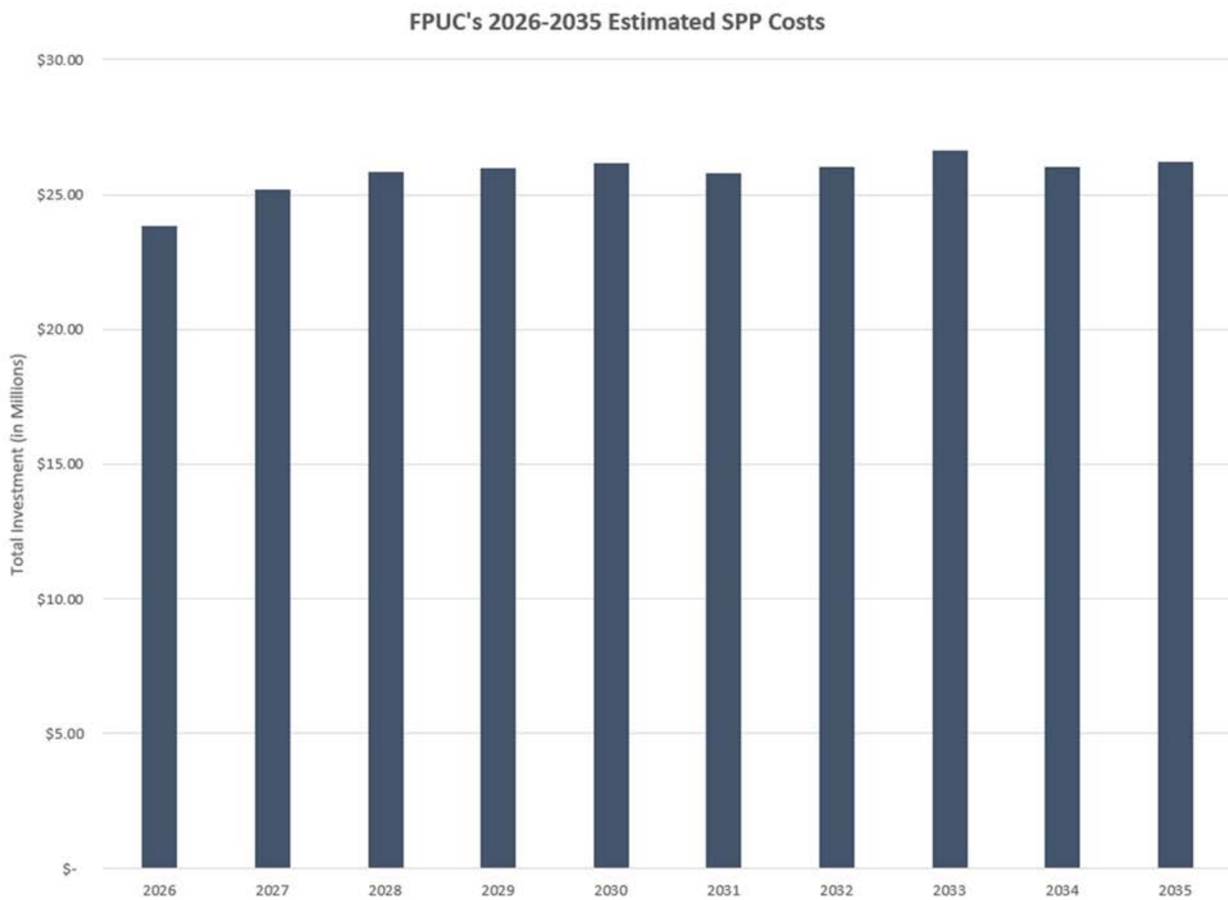


Figure 9 - Ten-year estimated investment profile for SPP Programs

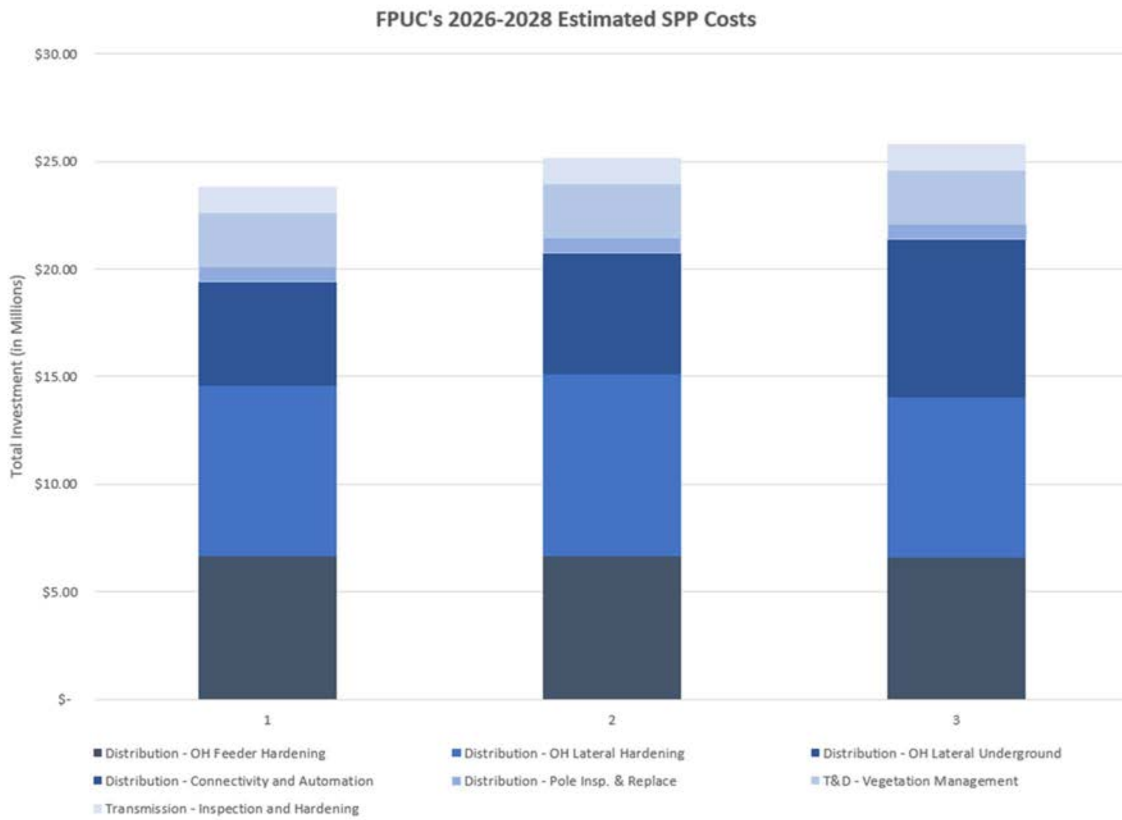


Figure 10 - Three-year estimated investment profile for SPP Programs

Storm Protection Program Investments (in Millions)		2026	2027	2028
New SPP Program	**Distribution Connectivity and Automation**	$0.00	$0.00	$2.51
Legacy SPP Programs	**Overhead Feeder Hardening**	$6.66	$6.66	$6.60
	Overhead Lateral Hardening	$7.93	$8.43	$7.43
	Overhead Lateral Undergrounding	$4.85	$5.67	$4.87
	Distribution Wood Pole Inspection and Replacement	$0.69	$0.69	$0.69
	T&D Vegetation Management	$2.50	$2.50	$2.50
	Transmission System Inspection and Hardening	$1.22	$1.22	$1.22
Totals		$23.85	$25.17	$25.82

Table 1 - Three-year estimated investment details for SPP Programs

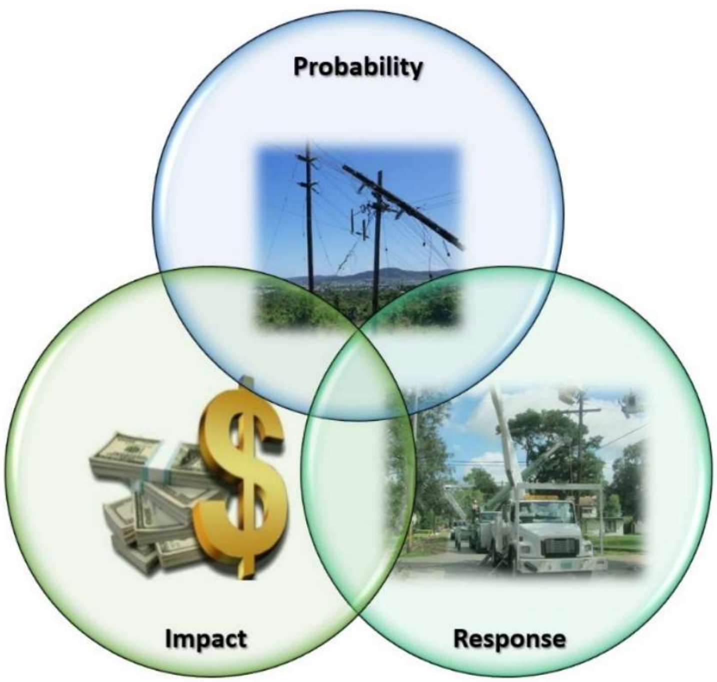
2.0 Resiliency Risk Model

Pike Engineering leveraged the use of its proprietary Resiliency Risk Model to evaluate the FPUC distribution system and develop a prioritized list of investment projects.

2.1 Structure

This Resiliency Risk Model evaluates risks and an electric system's resiliency against such risk by leveraging an algorithm that assesses a balanced approach between probability, response, and impact.

- Probability
  - The probability or likelihood that an extreme weather condition event will cause damage to existing utility infrastructure.
- Response
  - The utility's ability to appropriately respond to and recover from infrastructure damage caused by an extreme weather condition.
- Impact
  - The societal impact of the extreme weather condition caused electrical outage to the community being affected.



When assessing risk, and ultimately developing a prioritized list of investments based on risk, it is important to account for these three focused categories. Focus on one or two of these categories with complete disregard to the other may lead to unintended consequences such as increased costs or degrading reliability performance.

- **IMPACT & RESPONSE = ↑ CUSTOMER RATES**
- **PROBABILITY & RESPONSE = ↑ SOCIETAL COSTS**
- **PROBABILITY & IMPACT = ↑ CMI**

If a utility places focus on the impact of a severe weather event and their ability to respond to those events but disregards the probability of the event occurring in the first place, it can lead them to over-invest in infrastructure upgrades that will ultimately impact customer rates. Conversely, a focus on probability and response with disregard to the societal costs from a single event may lead a utility to under-invest in infrastructure strengthening and upgrade initiatives. Finally, a focus on the probability of an event to occur and the societal impact of such event without accounting for the utility's ability to respond to such event can lead to decreased reliability performance (increase in Customer Minutes of Interruption (CMI)) resulting from investments in other tactics and methods that do not promote a faster utility response or for which a utility may not be as adequately prepared to respond to.

This Risk Resiliency Model leverages data from several publicly available sources as well as FPUC specific data, into each of these categories to provide a balanced, systematic, and repeatable method to address extreme wind resiliency.

2.2 INPUTS

The Risk Resiliency Model applies quantitative data as inputs into an algorithm that calculates risk based on a balanced approach against Probability, Response, and Impact. The model leverages inputs from several public available sources in combination with FPUC specific system data. When quantitative data was not available, approximations were used based on experience and collaboration between FPUC and Pike Engineering.

Wind probability

Extreme Wind loading zones are outlined in NESC 250C (Figure 11 below). The zones were developed by the American Society of Civil Engineers (ASCE) in their 7-16 standards and were adopted by the NESC as design standards for structures greater than 60 feet in height. FPUC applies this standard (along with NESC Grade B) in the construction of overhead distribution facilities less than 60 feet in height when building to or strengthening existing facilities to extreme wind standards such as those in Feeder Hardening projects. Consistent with the 2023 updated map, FPUC has applied the 110mph zone to all facilities in both Divisions. To differentiate between feeders, wind probability calculations for the model are derived by utilizing the average age of poles on the feeder.

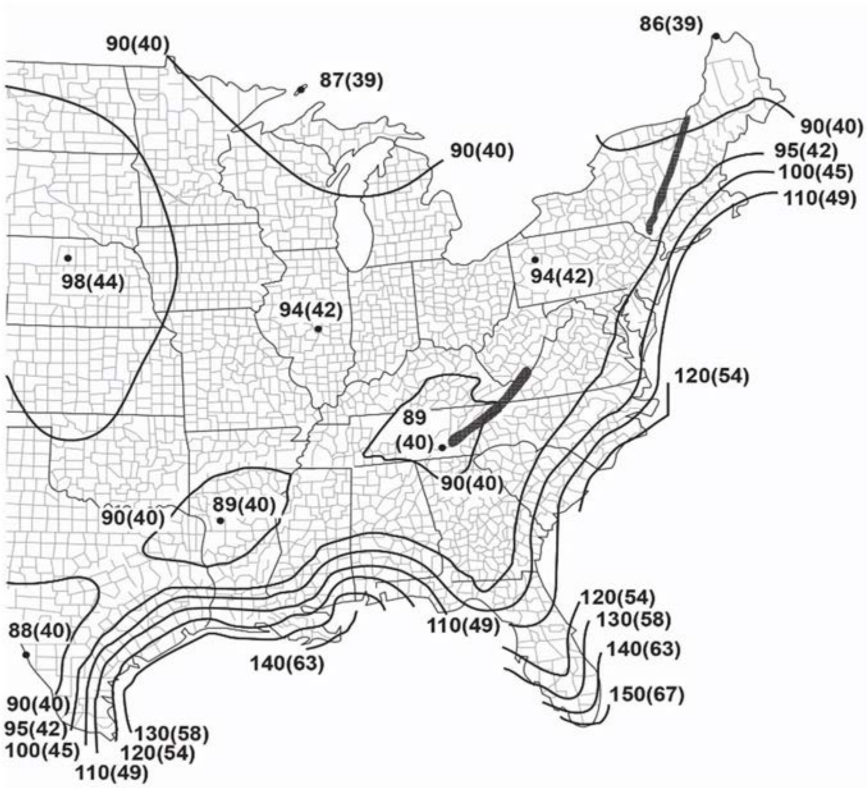


Figure 11 - NESC extreme wind zones

Flood/Storm Surge Potential

NOAA has developed Flood and Storm Surge potential hazard maps[9] for coastal and non-coastal regions across the United States. Pike Engineering overlaid FPUC Geographical Information System (GIS) system specific data containing asset locations across the NOAA maps to determine the Flood and Storm Surge Potential hazards for each evaluated scenario.

As shown in Figure 12, FPUC's NW Division has minimal flood hazard potential across most of the territory except for facilities serving communities located near the Apalachicola River (Blountstown and Bristol). Storm Surge and Flood Hazard potential varies greatly in the NE Division as shown in Figure 13.

[9] https://coast.noaa.gov/floodexposure/#-9476264,3599408,11z/eyJiIjoic3RyZWV0In0=

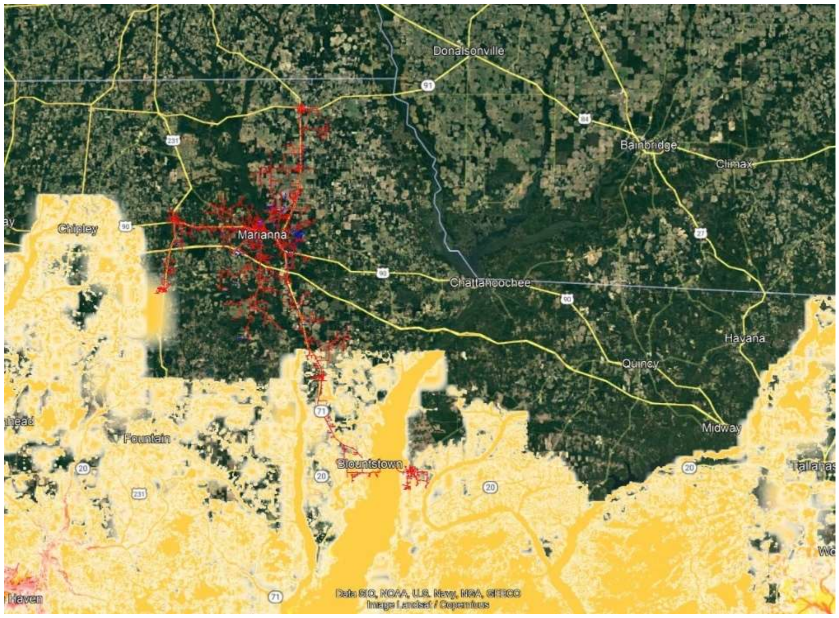


Figure 12- NOAA Coastal Flood Exposure Map - NW Division

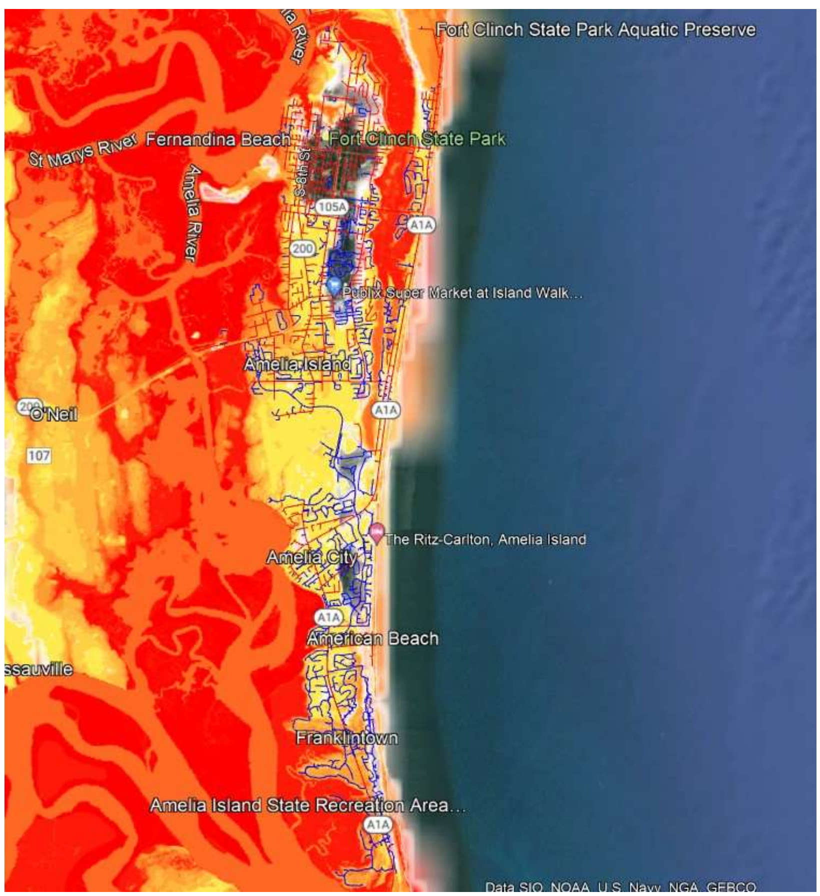


Figure 13 – NOAA Coastal Flood Exposure Map – NE Division

Past Performance

The historical reliability performance of FPUC's system during extreme and non-extreme weather conditions was analyzed and leveraged as the best indicator of future system performance during extreme weather events in a status quo ("do nothing") scenario.

Accessibility

FPUC system-specific GIS data was overlaid on top of aerial/satellite imagery as shown in Figures 14 and 15 to determine their accessibility (ability for FPUC to easily access utility assets with standard trucks and tools). Inaccessible areas, such as those shown in Figure 15, take longer to restore due to the inability to leverage truck and tools specially designed to provide efficiencies in the construction and maintenance of electric grids.

Figure 14 - Accessible Areas - NW Division

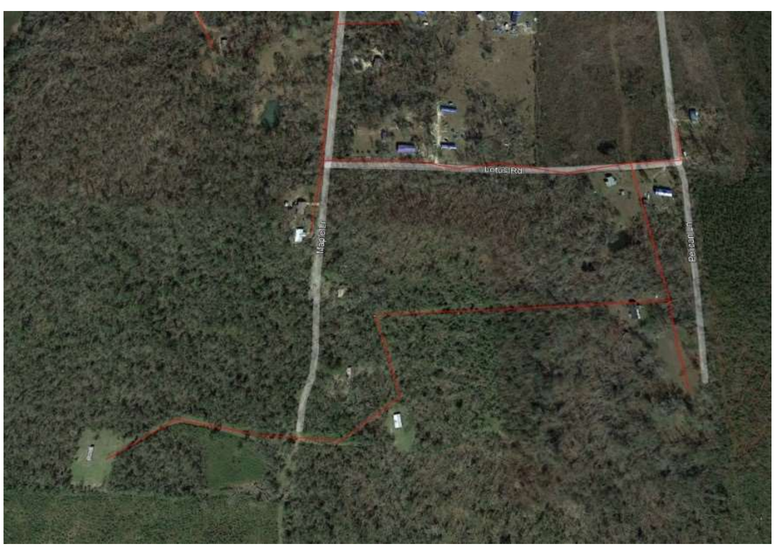


Figure 15 - Inaccessible Area - NW Division

Contingency

As mentioned earlier, it is practically and prudently impossible to eliminate all outages associated with extreme weather events. The ability to restore and recover unaffected areas of the distribution grid is essential in minimizing the customer impact associated with these events. This can prove to be problematic in more rural areas of a utility's service territory, particularly at the tail end of a distribution circuit. FPUC's service to customers in Liberty County, Florida is an example of this scenario where customers are served from a single overhead feeder that spans across the Apalachicola River. FPUC GIS data, electrical connectivity models, and discussions with FPUC personnel were leveraged to identify areas of the FPUC territory with this type of risk (Figure 16).

Figure 16 - Radial service to Liberty County customers

Vegetation Exposure

In late 2019, FPUC enlisted the assistance of Davey Resource Group to conduct a study[10] "to review their present line clearance operation, vegetation maintenance cycles, and vegetation workload throughout the electric system." The study was limited to the NW Division. As part of the findings, Davey Resource Group presented a "tree interference" calculation for each feeder circuit in the Division. The "tree interference" (vegetation exposure), expressed as a percentage of total overhead circuit miles, was leveraged for each analyzed scenario in the NW Division.

In the NE Division, an overlay of FPUC GIS system specific data against aerial/satellite imagery was used to determine approximate vegetation exposure for each analyzed scenario as shown in Figure 17 along Fernandina Beach's Historic District.

[10] Appendix C – Davey Resource Group - Trim Cycle and System Assessment; Florida Public Utilities - Mariana

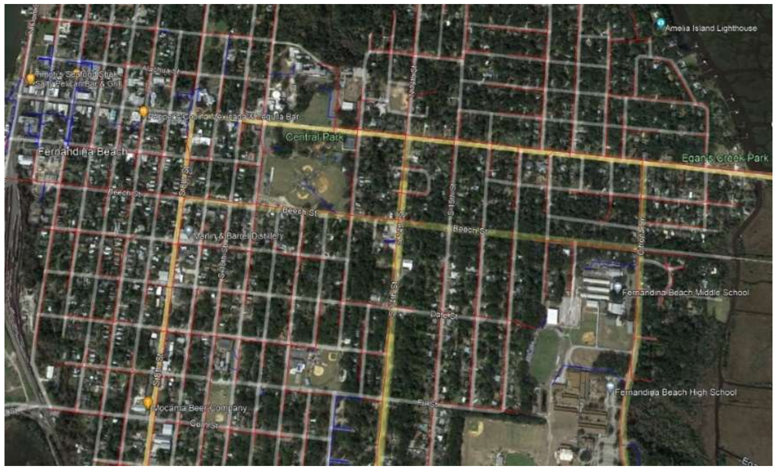


Figure 17 - Fernandina Beach Historic District - NE Division

Critical Load

FPUC's customer base was categorized into three tiers; Tier 1 – dedicated to scenarios containing hospitals or first responders, Tier 2 – dedicated to scenarios containing storm shelters, historical sites, major commercial retail centers, or large industrial customers, and Tier 3 – all others. These categories align with FPUC's prioritized methods of post major storm event restoration priority.

Customers Served

The total customers served by the analyzed circuit or line segment was used to estimate the impact of an electric outage for each analyzed scenario.

Interruption Cost Estimate

The Interruption Cost Estimate (ICE)[11] calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory (LBNL) and Nexant, Inc. This tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator is funded by the Energy Resilience Division of the U.S. Department of Energy's Office of Electricity (OE). This publicly available tool was leveraged to estimate the financial societal impact of each analyzed scenario.

[11] *https://icecalculator.com/home*

2.3 PRIORITIZATION

The Risk Resiliency Model leverages data inputs to evaluate and risk rank scenarios based on a balance of Probability, Response, and Impact. Results are presented in a quantitative format with projects representing the highest risk amongst the analyzed scenarios, represented with a higher risk resiliency score. The results of the model provide FPUC with a recommended portfolio of prioritized projects that when executed, will reduce restoration costs associated with future extreme weather events and improve overall service reliability to the impacted customers. While the model provides a prioritized portfolio, it is important to note that the prioritization is based on the above referenced inputs to the model and does not account for other factors that may influence FPUC's decision regarding the order of execution of these projects such as the availability of resources, the geographical separation of their Divisions, external influences such as pending Department of Transportation (DOT) projects, material availability, prudent balance of investments across Divisions, etc.

3.0 Program Descriptions & Benefits

The following section outlines the detailed descriptions, costs, and benefits of the currently approved SPP Programs with proposed incremental expenditure and the newly proposed Distribution Connectivity and Automation Program.

3.1 Overhead Feeder Hardening

Description

The FPUC system contains approximately 141 miles of overhead feeder backbone lines across 29 feeders. The Overhead Feeder Hardening Program will systematically upgrade all 141 miles to NESC 250C Extreme wind standards outlined in section 2.2 of this report.

As referenced in section 1.2, the backbone of a feeder resembles the major arteries of the distribution circuit that services a particular community. When a fault occurs on a backbone, upwards of 2,500 customers can be immediately impacted. Thus, the strengthening of these critical sections of the electric distribution grid to withstand damage during extreme weather conditions, can significantly reduce the impact these weather events can have.

As part of the hardening of the overhead lines, each line segment will be analyzed leveraging specialized software to ensure adherence to current NESC standards in place at the time of analysis. Applicable upgrades associated with this analysis such as upgrading of pole class or adding intermediate poles will be included as part of the design in addition to other upgrades that further strengthen the resiliency of the line against direct damage or ancillary damage that can be caused by extreme weather events. Such upgrades include:

- Replacement of previously identified deteriorated poles.
- Relocation of facilities to utility truck accessible areas, areas less prone to damage, or areas which can facilitate the restoration process.
- Undergrounding of feeders crossing major thoroughfares or where overhead hardening is not feasible, economically or otherwise, for a particular section.
- Upgrading the conductor size to one of higher tensile strength to better withstand damage from airborne debris or higher ampacity allowing for the re-route of power to and from alternate sources as part of the restoration process.
- Ensuring ancillary equipment and framing equipment on the pole has the adequate Basic Insulation Level (BIL) to withstand inadvertent faults from an increase in contamination such as wind induced salt spray.
- Adding additional guying to existing structures as necessary.
- Environmental upgrades such as avian protection, animal mitigation, and lightning protection.

Cost

The expected 10-year cost for this Program is approximately $66.3M covering approximately 80 miles of high priority overhead feeder improvements.

OH Feeder Hardening	2026	2027	2028
Capital ($MM)	$6.52	$6.53	$6.47
O&M ($MM)	$0.13	$0.13	$0.13
Units (miles)[12]	8	8	8
Total	$6.66	$6.66	$6.60

Table 2 - Overhead Feeder Hardening estimated 3-year costs

Cost/Benefit Comparison

Continuing in 2026, the Overhead Feeder Hardening Program will take approximately 20 years to complete. At its conclusion, the program is projected to have hardened approximately 141 miles of overhead feeder at a cost of approximately $115M[13].

Projected benefits associated with the Overhead Feeder Hardening program include a reduction in storm restoration costs and increase in service reliability; associated with a reduction in outage events during both extreme and non-extreme weather conditions. FPUC's data previously reported[14] to the Commission following Hurricanes Hermine, Matthew, and Irma, found no damage to hardened facilities. Additionally, post-storm data for Hurricane Michael found that hardened structures performed significantly better than non-hardened structures. A review[15] conducted by the Commission following Hurricanes Hermine, Matthew, Irma, and Nate found that the "Florida's aggressive hardening programs are working", "The length of outages was reduced markedly from the 2004-2005 storm season", and "Hardened overhead distribution facilities performed better than non-hardened facilities." FPUC believes the Overhead Feeder Hardening program will achieve the desired objectives outlined in Rule 25-6.030 of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." FPUC also agrees with the Commission's findings that "no amount of preparation can eliminate outages in extreme weather events" however, the utility can play a part in implementing programs that reduce outages and subsequent outage durations.

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[12] Reflected units exclude design only units and is strictly projected construction units in noted calendar year.
[13] *Represents 2025 dollars and does not account for increase in material costs or inflation over projected 30-year span.*
[14] *http://www.floridapsc.com/library/filings/2018/00499-2018/00499-2018.pdf*
[15] *http://www.floridapsc.com/library/filings/2018/04847-2018/04847-2018.pdf*

3.2 Overhead Lateral Hardening

Description

The FPUC systems contain approximately 575 miles of overhead lateral lines across 29 feeders. The Overhead Lateral Hardening Program will systematically upgrade key laterals to NESC 250C Extreme wind standards outlined in section 2.2 of this report.

As referenced in section 1.2, a typical overhead lateral can have upwards of 200 to 300 customers. Thus, the strengthening of these critical sections of the electric distribution grid to withstand damage during extreme weather conditions, can significantly reduce the impact these weather events can have.

As part of the hardening of the overhead lines, each line segment will be analyzed leveraging specialized software to ensure adherence to NESC standards. Applicable upgrades associated with this analysis such as upgrading of pole class or adding intermediate poles will be included as part of the design in addition to other upgrades that further strengthen the resiliency of the line against direct damage or ancillary damage that can be caused by extreme weather events. Such upgrades include:

- Replacement of previously identified deteriorated poles.
- Relocation of facilities to utility truck accessible areas, areas less prone to damage, or areas which can facilitate the restoration process.
- Upgrading the conductor size to one of higher tensile strength to better withstand damage from airborne debris or higher ampacity allowing for the re-route of power to and from alternate sources as part of the restoration process.
- Ensuring ancillary equipment and framing equipment on the pole has the adequate Basic Insulation Level (BIL) to withstand inadvertent faults from an increase in contamination such as wind induced salt spray.
- Adding additional guying to existing structures as necessary.
- Environmental upgrades such as avian protection, animal mitigation, and lightning protection.
- Upgrading traditional fusing to cut-out mounted reclosers intended to minimize the number of outages associated with temporary or transient fault conditions.

Cost

The expected 10-year cost for this Program is approximately $77.7M covering approximately 80 miles of high priority overhead lateral improvements.

OH Lateral Hardening	2026	2027	2028
Capital ($MM)	$7.55	$8.48	$7.28
O&M ($MM)	$0.15	$0.17	$0.15
Units (miles)[16]	8	8	8
Total	**$7.71**	**$8.65**	**$7.43**

Table 3 - Overhead Lateral Hardening estimated 3-year costs

[16] Reflected units exclude design only units and is strictly projected construction units in noted calendar year.

Cost/Benefit Comparison

Continuing in 2026, the Overhead Lateral Hardening Program will take approximately 20 years to complete. At its conclusion, the program is projected to have hardened approximately 142 miles of multi-phase overhead laterals at a cost of approximately $137M[17] which represents 100% of the multi-phase overhead laterals in the FPUC overhead system.

Projected benefits associated with the Overhead Lateral Hardening program include a reduction in storm restoration costs and increase in service reliability; associated with a reduction in outage events during both extreme and non-extreme weather conditions. FPUC's data previously reported[18] to the Commission following Hurricanes Hermine, Matthew, and Irma, found no damage to hardened facilities. Additionally, post-storm data for Hurricane Michael found that hardened structures performed significantly better than non-hardened structures. A review[19] conducted by the Commission following Hurricanes Hermine, Matthew, Irma, and Nate found that the "Florida's aggressive hardening programs are working", "The length of outages was reduced markedly from the 2004-2005 storm season", and "Hardened overhead distribution facilities performed better than non-hardened facilities." FPUC believes the Overhead Lateral Hardening program will achieve the desired objectives outlined in Rule 25-6.030 of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." FPUC also agrees with the Commission's findings that "no amount of preparation can eliminate outages in extreme weather events" however, the utility can play a part in implementing programs that reduce outages and subsequent outage durations.

3.3 Overhead Lateral Undergrounding

Description

As noted previously, FPUC's system contains approximately 575 miles of overhead lateral lines across 29 feeders; 433 miles of which are single phase. The Overhead Lateral Undergrounding Program will address the systematic undergrounding in place or relocation and undergrounding of the single phase overhead electric facilities, many of which are located in heavily vegetated areas, environmentally sensitive areas, or in areas where upgrading the overhead construction to NESC extreme wind standards is not practical or consistent with industry design standards.

Additionally, the Overhead Lateral Undergrounding program targets lateral overhead crossings along major thoroughfares in the Company's service territory, specifically along I-10, A1-A, and SR-200. Undergrounding primary and secondary overhead facilities reduces obstructions to roadways that are essential for providing access to restoration crews and other emergency response personnel, thus accelerating power restoration and community access to these vital resources.

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[17] *Represents 2025 dollars and does not account for increase in material costs or inflation over 30-year span.*
[18] *http://www.floridapsc.com/library/filings/2018/00499-2018/00499-2018.pdf*
[19] *http://www.floridapsc.com/library/filings/2018/04847-2018/04847-2018.pdf*

As referenced in section 1.2, a typical overhead lateral can have upwards of 200 to 300 customers. Thus, the strengthening of these critical sections of the electric distribution grid to withstand damage during extreme weather conditions can significantly reduce the impact these weather events can have.
As part of the undergrounding of the overhead lines, each line segment will be relocated to utility truck accessible areas in the front of the premise as necessary to facilitate restoration and maintenance activities. Additionally, FPUC will be installing meter base adaptors to minimize the customer impact associated with the conversion. These adaptors allow customers to retain their existing meter and meter enclosure, minimizing the need for costly permits and inspections associated with electrical panel upgrades that may otherwise be necessary.

Cost

The expected 10-year cost for this Program is approximately $49.3M covering approximately 30 miles of high priority overhead lateral improvements.

OH Lateral Undergrounding	2026	2027	2028
Capital ($MM)	$4.76	$5.56	$4.77
O&M ($MM)	$0.10	$0.11	$0.10
Units (miles)[20]	3	3	3
Total	**$4.85**	**$5.67**	**$4.87**

Table 4 - Overhead Lateral Undergrounding estimated 3-year costs

Cost/Benefit Comparison

Continuing in 2026, the Overhead Lateral Undergrounding Program will take approximately 30 years to complete. At its conclusion, the program is projected to have undergrounded approximately 93 miles of single-phase overhead laterals at a cost of approximately $82M.[21]

Projected benefits associated with lateral undergrounding program include a reduction in storm restoration costs and increase in service reliability associated with a reduction in outage events during both extreme and non-extreme weather conditions. FPUC's data previously reported[22] to the Commission following Hurricanes Hermine, Matthew, Maria, and Nate, found no repairs or replacements of underground facilities. Additionally, damage to underground facilities associated with Hurricane Michael was less than 1%, with one transformer and three switchgears replaced. The reliability performance of underground systems routinely outperforms that of overhead facilities as noted annually[23] on FPUC's Overhead to Underground comparison on both an "Actual" (inclusive of extreme weather events) and "Adjusted" basis. This finding was also substantiated by a review[24] conducted by the Commission following Hurricanes Hermine, Matthew, Irma, and Nate found which found that "Underground facilities performed much better compared to overhead facilities."

[20] Reflected units excludes design only units and is strictly projected construction units in noted calendar year.
[21] *Represents 2025 dollars and does not account for increase in material costs or inflation over 30-year span.*
[22] http://www.floridapsc.com/library/filings/2018/00499-2018/00499-2018.pdf
[23] http://www.floridapsc.com/ElectricNaturalGas/ElectricDistributionReliability
[24] *http://www.floridapsc.com/library/filings/2018/04847-2018/04847-2018.pdf*

3.4 Distribution Connectivity and Automation

Description

The FPUC system contains approximately 141 miles of overhead feeder backbone lines across 29 feeders. The Distribution Connectivity and Automation Program will systematically review all 141 miles of feeder for strategic points of interconnection, segmentation, and automation.

As referenced in section 1.2, the backbone of a feeder resembles the major arteries of the distribution circuit that services a particular community. When a fault occurs on a backbone, upwards of 2,500 customers can be immediately impacted. Thus, mitigating the impacted customers via protective segmentation or by automatically isolating damage and rerouting power from unaffected areas of the grid during extreme weather conditions, can significantly reduce the impact these weather events can have.

The addition of feeder ties in a distribution system enhances the reliability and flexibility of the network. By interconnecting feeders, the system has the flexibility to redirect power flow during outages or disruptions, ensuring faster restoration to unaffected customers. Feeder ties enable the system to balance loads more effectively, which can also help optimize energy distribution across various parts of the grid. In scenarios where one feeder faces a fault, the feeder tie can allow power to flow from an alternative path, minimizing downtime and improving overall system resilience. This approach is crucial for managing outages, reducing downtime, and enhancing customer satisfaction.

When combined with protective interrupting devices such as reclosers with automation capability, this program allows for the restoration of power to unaffected sections of the grid without human intervention. Protective interrupting devices at the feeder and lateral level have advanced capabilities to detect faults and either restore or isolate the impacted section(s) of the grid based on analyzed fault information. Peer to peer communication allows these devices to “talk” to each other, working together as a team to implement pre-programmed set instruction(s) that allow for automated restoration. Integrating these devices into the distribution network, automates fault detection and restoration processes, improving grid reliability and reducing the need for manual intervention.

As part of the Distribution Connectivity and Automation Program, each feeder will be evaluated to assess its suitability for additional feeder ties. Additionally, feeder protective interrupting device(s) will be installed on every feeder, and each lateral will be reviewed for potential upgrades using reclosing fuses.

Cost

The expected 10-year cost for this Program is approximately $20.1M assessing and upgrading 24 feeders for intertie ability and/or segmentation and automation improvements. On August 8, 2024, FPUC filed a petition with the Commission for a rate increase as part of Docket No. 20240099-EI in which amongst other things, includes a distribution automation program. If approved, FPUC will appropriately account for the recovery granted through base rates in its annual SPP Cost Recovery Clause filings in the same manner it is currently doing so for other legacy programs currently under similar split recovery mechanisms.

Automation & Connectivity	2026	2027	2028
Capital ($MM)	$0	$0	$2.46
O&M ($MM)	$0	$0	$0.05
Units (feeders)[25]	0	0	3
Total	$0	$0	$2.51

Table 5 - Distribution Connectivity and Automation 3-year costs

Cost/Benefit Comparison

Beginning in 2028, the Distribution Connectivity and Automation Program will take approximately 10 years to complete. At its conclusion, the program is projected to have reviewed, assessed, and upgraded for connectivity and automation 141 miles of overhead feeder at a cost of approximately $30M[26].

Projected benefits associated with the Distribution Connectivity and Automation program include a reduction in storm restoration costs and increase in service reliability; associated with a reduction in outage events during both extreme and non-extreme weather conditions. Deployment of feeder protective interrupting devices with automation capabilities have proven reliability benefits in Florida Grids[27]. The automation features, including fault detection and restoration, reduce truck rolls, enhance crew productivity, and strengthen the system's ability to react to disruptions in real-time. Additionally, in cases where feeder ties are not feasible or economically viable, feeder protective interrupting devices still provide a reliability benefit without a complicated communications network[28]. To date, FPUC does not deploy protective interruption devices along its mainline feeders in the Northeast Division. FPUC believes the Distribution Connectivity and Automation program will achieve the desired objectives outlined in Rule 25-6.030 of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability."

[25] Reflected units exclude design only units and is strictly projected construction units in noted calendar year.
[26] *Represents 2025 dollars and does not account for increase in material costs or inflation over 30-year span.*
[27] Case Study – S&C Florida
[28] Case Study – S&C Automation

3.5 Distribution Pole Inspection and replacements

Description

In alignment with FPSC Order No. PSC-06-0144, FPUC implemented an 8-year cycle wood pole inspection program. The most current edition of the National Electric Safety Code (NESC) serves as a basis for the design of replacement poles that fail inspection. Grade 'B' construction, as described in Section 24 of the NESC, has been adopted as the standard of construction for designing new pole installations and the replacement of reject poles in each FPUC Electric Division (NE & NW). Extreme wind loading, as specified in rule 250C and figure 250-2(a) of the NESC, has been adopted for replacement poles.

Wood pole inspections are performed by a qualified wood pole inspection contractor. The inspection process is a multi-step process that may involve one or more of visual inspection techniques, sound and bores, and excavations with treatments. Inspection results are summarized for each division by the contractor and include bar charts and tables that show inspection results summary, failure rates, and pole ages. The number of inspections may vary from year-to-year based upon a variety of factors however, FPUC completes all required wood pole inspections during the eight-year wood pole inspection cycle. In 2024 FPUC began the first year of the third cycle for both divisions.

Beginning in 2014, the inspections were performed with modified criteria for chromated copper arsenate (CCA) treated pole inspections. CCA poles less than 21 years of age are visually inspected, sounded, and selectively bored. Boring is performed only if internal decay is suspected. Unless a pole failed sound and bore, a full excavation is not performed on these poles.

The contractor performs Strength Assessment tests on selected poles to compare the current measured circumference to the original circumference of the pole. The effective circumference of the pole is determined to ensure that the current condition of the pole meets the requirements of NESC Section 26 "Strength Requirements". Beginning in 2010, pole inspection criteria were enhanced to include LoadCalc, a program used by the contractor to determine pole loading, analysis on poles with remaining strength at or below 67%. Poles identified by the contractor as being loaded at or above 100% are re-evaluated by FPUC engineers using a program called PoleForeman. NESC Grade B construction & 60 mph winds provide the basis for calculations. Poles loaded at or above 100% following re-evaluation are marked for replacement. If the 'required' remaining strength resulting from the combined strength and load analysis indicates that the pole is not suited for continued use, the contractor rejects the pole and reports it to FPUC for follow-up.

Poles marked for replacement are re-inspected by FPUC employees and assigned a priority based upon potential hazard to public and employee safety. Repairs are then made in order of priority. FPUC policy is to replace all reject poles in lieu of bracing "restorable" reject poles. Poles are prioritized for replacement using the reject severity level awarded by the inspector as the basis. Poles are analyzed by FPUC engineers who leverage PoleForeman software to ensure the new poles meet the storm hardening criteria discussed in the first paragraph of this section.

Under the currently approved SPP, FPUC accelerated the replacement of poles in its backlog. Most of these poles were resultant from post Hurricane Michael inspections. FPUC has approximately 26,700 wood distribution poles and projects to annually invest approximately $0.69M in their inspection & replacement[29] moving forward.

Cost

The expected 10-year cost for this Program is approximately $6.90M covering approximately 750 high priority pole replacements.

Dist. Pole Insp. & Replace	2026	2027	2028
Capital ($MM)	$0.50	$0.50	$0.50
O&M ($MM)	$0.19	$0.19	$0.19
Units (poles)	75	75	75
Total	**$0.69**	**$0.69**	**$0.69**

Table 6 – Distribution Pole Inspection and Replacements estimated 3-year costs

Cost/Benefit Comparison

Continuing since 2008, the Distribution Pole Inspection and Replacement program is an on-going program that assures the structural integrity of wood distribution poles.

Projected benefits associated with the Distribution Pole Inspection and Replacement program include a reduction in storm restoration costs and increase in service reliability; associated with a reduction in outage events during both extreme and non-extreme weather conditions. FPUC's data previously reported[30] to the Commission following Hurricanes Hermine, Matthew, and Irma, found no damage to hardened facilities. Additionally, post-storm data for Hurricane Michael found that hardened structures performed significantly better than non-hardened structures. A review[31] conducted by the Commission following Hurricanes Hermine, Matthew, Irma, and Nate found that the "Florida's aggressive hardening programs are working", "The length of outages was reduced markedly from the 2004-2005 storm season", and "Hardened overhead distribution facilities performed better than non-hardened facilities." FPUC believes the continuation of the Distribution Pole Inspection and Replacement program will achieve the desired objectives outlined in Rule 25-6.030 of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." FPUC also agrees with the Commission's findings that "no amount of preparation can eliminate outages in extreme weather events" however, the utility can play a part in implementing programs that reduce outages and subsequent outage durations.

[29] Based on average projected failure rate of 2.2%
[30] http://www.floridapsc.com/library/filings/2018/00499-2018/00499-2018.pdf
[31] http://www.floridapsc.com/library/filings/2018/04847-2018/04847-2018.pdf

3.6 Transmission System Inspection and Hardening

Description

The 138kV Transmission system in the NE Division was constructed using concrete poles, steel poles, and steel towers. The construction generally complies with storm hardening requirements. Transmission inspections are performed on all transmission facilities and include patrols of the 138kV and 69kV transmission lines owned by FPUC. This inspection ensures that all structures have a detailed inspection performed at a minimum of every six years; the most recent of which was completed in 2024. The inspection includes fifty (50) 138kV structures and two hundred seventeen (217) 69kV structures. The inspections ensure that all transmission towers and other transmission line supporting equipment such as insulators, guying, grounding, conductor splicing, cross-braces, cross-arms, bolts, etc. are structurally sound and firmly attached.

Substation equipment is also inspected annually to document the integrity of the facility and identify any deficiencies that require action. Substations are inspected to ensure that all structures, buss work, insulators, grounding, bracing, bolts, etc. are structurally sound and firmly attached.

The 69kV transmission system consists of a total of 217 poles of which, as of the time of this filing, 134 are concrete and 83 are wood structures. All installations met the NESC code requirements in effect at the time of construction. A policy of replacing existing wood poles with concrete structures has been in place for some time. This policy requires that when it becomes necessary to replace a wood pole, due to construction requirements or concerns with the integrity of the pole, a concrete pole that meets current NESC codes and storm hardening requirements will be utilized. FPUC's budgeted projections for wood pole replacements versus actuals achieved varies from year to year due to several factors inclusive of resource allocation, material availability, external constraints, and others. This program is projected to accelerate the full replacement of the Commission-approved 69kV wood poles for completion within this planning period as well as the replacement of concrete structures no longer meeting current code or FPUC specifications which may inhibit restoration.

FPUC has 267 Transmission structures in the NE Division and none in the NW Division annually investing approximately $1.22M in their inspection & replacement.

Cost

The expected 10-year cost for this Program is approximately $12.3M accelerating the replacement of all remaining 69kV wooden poles.

Trans. Wood Pole Replace	2026	2027	2028
Capital ($MM)	$1.20	$1.20	$1.20
O&M ($MM)	$0.02	$0.02	$0.02
Units (poles)	12	12	12
Total	**$1.22**	**$1.22**	**$1.22**

Table 7 – Transmission System Inspection and Hardening estimated 3-year costs

Cost/Benefit Comparison

FPUC plans on continuing this Commissioned-approved initiative and accelerate the completion of the Transmission Wood Pole Replacement program. The program assures the structural integrity of wood transmission poles. At its conclusion, all 69kV wood poles within FPUC's Transmission system will have been replaced with concrete and the cyclical inspections will continue.

Projected benefits associated with the Transmission Wood Pole Replacement program include a reduction in storm restoration costs and increase in service reliability; associated with a reduction in outage events during both extreme and non-extreme weather conditions. Transmission lines are the main supply lines between generating stations and the local substations that connect to the distribution grid. An outage to a Transmission line can affect tens of thousands of customers at one time. FPUC's data previously reported[32] to the Commission following Hurricanes Hermine, Matthew, and Irma, found no damage to hardened facilities. Additionally, post-storm data for Hurricane Michael found that hardened structures performed significantly better than non-hardened structures. A review[33] conducted by the Commission following Hurricanes Hermine, Matthew, Irma, and Nate found that the "Florida's aggressive hardening programs are working", "The length of outages was reduced markedly from the 2004-2005 storm season", and "Hardened overhead distribution facilities performed better than non-hardened facilities." FPUC believes the continuation of the Transmission Wood Pole Replacement program will achieve the desired objectives outlined in Rule 25-6.030 of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." FPUC also agrees with the Commission's findings that "no amount of preparation can eliminate outages in extreme weather events;" however, the utility can play a part in implementing programs that reduce outages and subsequent outage durations.

3.7 Transmission & Distribution (T&D) Vegetation Management

Description

The T&D Vegetation Management program had historically worked towards the accomplishment of a three-year vegetation management cycle on main its approximately 141 miles of feeders and a six-year vegetation management cycle on its approximately 575 miles of laterals on the system.

The program included the following:

1. Three-year vegetation management cycle on all main feeders.
2. Six-year vegetation management cycle on all laterals.
3. Increased participation with local governments to address improved overall reliability due to tree related outages.
4. Information made available to customers regarding the maintenance and placement of trees.

[32] *http://www.floridapsc.com/library/filings/2018/00499-2018/00499-2018.pdf*
[33] *http://www.floridapsc.com/library/filings/2018/04847-2018/04847-2018.pdf*

Based upon current tree trimming crew levels, FPUC also made reasonable efforts to address the annual inspection of main feeders to critical infrastructure prior to the storm season to identify & perform the necessary trimming and addresses danger trees located outside the normal trim zone and located near main feeders as reported.

The plan also managed the cyclical trimming along the approximately 3.6 miles and 12 miles of 138kV and 69kV Transmission lines respectively. These Transmission lines have historically been included with the distribution main feeders' 3-year trim cycle.

In 2014, FPUC initiated a new cycle of its 3-year feeder and 6-year lateral vegetation management program. Data from this and the preceding cycles was analyzed for opportunities for improvements. In late 2019, FPUC enlisted the assistance of Davey Resource Group to conduct a study[34] "to review their present line clearance operation, vegetation maintenance cycles, and vegetation workload throughout the electric system." The study was limited to the NW Division but can be extrapolated to the NE Division which followed the same standards. As part of the findings, Davey Resource Group found that it was in "FPUC's best interest to convert to a 4-year, cyclical, circuit-based vegetation management plan."

FPUC aligned with the recommended 4-year cycle during its currently approved SPP. This approach allows FPUC to achieve and maintain a designated cycle for each circuit. The prioritization of each circuit is determined based on a customer count, critical infrastructure and vegetation-related customer interruptions.

Cost

The costs associated with a four-year vegetation management cycle as recommended by the Davey Resource Group study, is approximately $2.5M annually. The expected 10-year cost for this Program is approximately $25.0M to continue a 4-year cycle for all transmission lines, main feeders, and laterals.

Vegetation Management	2026	2027	2028
Capital ($MM)	$-	$-	$-
O&M ($MM)	$2.50	$2.50	$2.50
Units (miles)	180	180	178
Total	**$2.50**	**$2.50**	**$2.50**

Table 8 - Transmission and Distribution Vegetation Management estimated 3-year costs

[34] Appendix B – Davey Resource Group - Trim Cycle and System Assessment; Florida Public Utilities - Mariana

Cost/Benefit Comparison

Projected benefits associated with the T&D Vegetation Management program include a reduction in storm restoration costs and increase in service reliability; associated with a reduction in outage events during both extreme and non-extreme weather conditions. FPUC's data previously reported to the Commission following Hurricanes Hermine, Matthew, and Irma, found that the number one driver for protracted restoration times during Hurricanes Matthew, Hermine, and Irma was the clearing of vegetation. Additionally, damage reported during these same storms was the result of falling trees and limbs.[35] More recently, damage experienced by FPUC in its Northeast territory during Hurricane Helene was also largely attributed to vegetation issues. A review[36] conducted by the Commission following Hurricanes Hermine, Matthew, Irma, and Nate also found that "the primary causes of power outages came from outside the utilities' rights of way including falling trees, displaced vegetation, and other debris." Together, these findings highlight the importance of cyclical vegetation management programs as well as the efficacy of FPUC's vegetation management program in limiting vegetation-related outages from within the right-of-way or utility easement. FPUC believes the continuation of the T&D Vegetation Management program will achieve the desired objectives outlined in Rule 25-6.030 of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability."

[35] *http://www.floridapsc.com/library/filings/2018/00499-2018/00499-2018.pdf*
[36] *http://www.floridapsc.com/library/filings/2018/04847-2018/04847-2018.pdf*

4.0 ESTIMATE OF ANNUAL JURISDICTIONAL REVENUE REQUIREMENTS

Pursuant to Rule 25-6.030(3)(g), F.A.C., the table below provides the estimated annual jurisdictional revenue requirements for each year of the SPP.

Year	Estimated Annual Revenue Requirements ($MM)
2026	$9.67
2027	$12.23
2028	$14.99
2029	$17.53
2030	$20.17
2031	$22.58
2032	$25.18
2033	$27.67
2034	$29.87
2035	$32.01

Table 9 – Estimated Annual Revenue Requirements

The above estimated revenue requirements are consistent with the program cost estimates provided as of the time of this filing. Actual program costs and subsequent program costs submitted for cost recovery through the Storm Protection Plan Cost Recovery Clause as outlined in Rule 25-6.031, F.A.C., could vary from the estimates above. A true up of estimated versus actual costs for these programs will be performed at the time of the cost recovery filing consistent with the Commission's rule. Calculations shown are based on total SPP expenditures irrespective of whether costs are recovered in base rates or through the SPPCRC.

5.0 ESTIMATE OF RATE IMPACTS FOR FIRST THREE YEARS OF SPP

Pursuant to Rule 25-6.030(3)(h), F.A.C., the table below provides the rate impacts for each year of the first three years of the SPP for FPUC's typical residential, commercial, and industrial customers. Calculations shown are based on total SPP expenditures irrespective of whether costs are recovered in base rates or through the SPPCRC.

Estimated SPP Rate Impacts per 1,000kWh Residential	2026	2027	2028
Total SPP Estimate	$17.30	$21.82	$26.77
Typical Commercial bill Increase %	1.61%	4.19%	6.15%
Typical Industrial bill Increase %	20.81%	24.36%	30.06%

Table 10 – Estimated SPP Rate Impacts

FPUC has not identified any implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the proposed SPP. As previously noted, FPUC's proposed 2026-2035 SPP is a combination of previously Commission-approved Storm Protection Plan Programs, some of which contain incremental investments, as well as a newly proposed Program across FPUC's Distribution system. As part of the currently approved plan, FPUC implemented a methodical ramp up of investments during the first three years of the SPP of which, in addition to other logistical reasons mentioned earlier in this report, this methodical ramp up of investments mitigated the resulting rate impact in the first three years of the plan and allows for the Hurricane Michael cost recover surcharge to expire.[37]

[37] http://www.floridapsc.com/library/filings/2020/11003-2020/11003-2020.pdf

6.0 Project Details

This section contains the specific project details for the first year of the plan. Future year project details will be provided as part of the annual plan updates and subsequent SPP filings.

6.1 Overhead Feeder Hardening

All FPUC feeders were risk ranked in alignment with the Risk Resiliency Model discussed in Section 2 of this report. Circuits were analyzed and prioritized via an algorithm that balances Probability, Response, and Impact. Each feeder circuit was assigned a risk score based on the model's calculation providing FPUC with a prioritized, holistic view of their system. FPUC leveraged the model's recommendation and supplemented it with other variables to identify the Overhead Feeder Hardening projects for the first three years of the plan. Project details for year one (2026) of the plan are shown in the Table 10 below.

Project ID	Feeder ID	Units (Miles)	Total Cust	Start Date	Comp. Date	2026 Cost ($M)	Prior Storm Impact
Cottondale Phase 4 Construction	9866	2.36	426	1/25	12/26	$1.83	Yes
Bristol Phase 1 Construction	9882	1.14	1234	1/26	12/27	$0.88	Yes
Bristol Phase 3 Design	9882	3.79	69	1/26	12/26	$0.15	Yes
South Fletcher Phase 1 Construction	102	0.11	1630	1/25	12/26	$0.09	Yes
South Fletcher Phase 2 Construction	102	1.7	799	1/26	12/26	$1.35	Yes
Sadler Nectarine Phase 1 Construction	215	2.13	1396	1/26	12/26	$1.65	Yes
Fifteenth Street Phase 1 Construction	209	0.52	1394	1/26	12/27	$0.40	Yes
Amelia Island Parkway Phase 1 Design	312	1.03	1000	1/26	12/26	$0.04	Yes
Eleven Street Phase 1 Design	212	3.31	1091	1/26	12/26	$0.13	Yes

Table 11 – Overhead Feeder Hardening 2026 Project Details

6.2 Overhead Lateral Hardening

All FPUC feeders were risk ranked in alignment with the Risk Resiliency Model discussed in Section 2 of this report. Circuits were analyzed and prioritized via an algorithm that balances Probability, Response, and Impact. Each feeder circuit was assigned a risk score based on the model's calculation providing FPUC with a prioritized, holistic view of their system. FPUC leveraged the model's recommendation and supplemented it with other variables at the circuit level to identify the specific Overhead Lateral Hardening projects for the first three years of the plan. Project details for year one (2026) of the plan are shown in the Table 10 below.

Project ID	Feeder ID	Units (Miles)	Total Cust	Start Date	Comp. Date	2026 Cost ($k)	Prior Storm Impact
FS.1740 Lateral Hardening Design	9882	0.24	100	1/26	12/26	$19.26	Yes
FS.1756 Lateral Hardening Design	9882	0.48	8	1/26	12/26	$38.30	Yes
FS.1704 Lateral Hardening Design	9882	0.34	16	1/26	12/26	$27.63	Yes
FS.1720 Lateral Hardening Design	9882	0.13	2	1/26	12/26	$10.81	Yes
FS.1757 Lateral Hardening Design	9882	0.13	2	1/26	12/26	$10.05	No
FS.1755 Lateral Hardening Design	9882	0.04	1	1/26	12/26	$2.94	Yes
FS.1772 Lateral Hardening Design	9882	0.03	2	1/26	12/26	$2.55	No
FS.1787 Lateral Hardening Design	9882	1.72	186	1/26	12/26	$138.10	No
FS.1792 Lateral Hardening Design	9882	1.71	18	1/26	12/26	$137.48	No
FS.1779 Lateral Hardening Design	9882	1.23	126	1/26	12/26	$98.80	No
FS.1794 Lateral Hardening Design	9882	0.77	75	1/26	12/26	$61.95	Yes
FS.1783 Lateral Hardening Design	9882	0.49	18	1/26	12/26	$39.71	Yes
FS.1798 Lateral Hardening Design	9882	0.46	16	1/26	12/26	$36.56	No
FS.1802 Lateral Hardening Design	9882	0.21	2	1/26	12/26	$17.12	No
FS.1796 Lateral Hardening Design	9882	0.18	14	1/26	12/26	$14.69	No
FS.17984 Lateral Hardening Design	9882	0.18	2	1/26	12/26	$14.13	No
FS.1799 Lateral Hardening Design	9882	0.06	5	1/26	12/26	$4.92	No
FS.1800 Lateral Hardening Design	9882	0.04	1	1/26	12/26	$3.09	No
FS.1785 Lateral Hardening Design	9882	0.03	1	1/26	12/26	$2.50	No
FS.1907 Lateral Hardening Design	210	0.23	12	1/26	12/26	$18.63	Yes
FS.1994 Lateral Hardening Design	210	0.92	538	1/26	12/26	$73.88	No
FS.2035 Lateral Hardening Design	210	0.04	14	1/26	12/26	$3.43	No
FS.1995 Lateral Hardening Design	210	0.12	23	1/26	12/26	$9.62	No
FS.1905 Lateral Hardening Design	210	0.36	58	1/26	12/26	$28.78	No
FS.1910 Lateral Hardening Design	210	0.28	70	1/26	12/26	$22.52	No
FS.1915 Lateral Hardening Design	210	0.56	2	1/26	12/26	$44.64	No
FS.1997 Lateral Hardening Design	210	0.87	2	1/26	12/26	$70.03	Yes
FS.2011 Lateral Hardening Design	210	0.34	46	1/26	12/26	$27.04	Yes
FS.120 Lateral Hardening Construct	9866	0.18	7	1/25	12/26	$107.09	Yes
FS.116 Lateral Hardening Construct	9866	0.34	41	1/25	12/26	$206.29	Yes
FS.114 Lateral Hardening Construct	9866	0.04	1	1/25	12/26	$26.30	Yes
FS.84434 Lateral Hardening Construct	9866	0.04	1	1/25	12/26	$27.00	No
REC.2858 Lateral Hardening Construct	9866	1.23	390	1/25	12/26	$754.70	Yes

FS.95 Lateral Hardening Construct	9866	0.05	12	1/25	12/26	$28.16	Yes
FS.112 Lateral Hardening Construct	9866	0.03	1	1/25	12/26	$18.31	No
FS.99 Lateral Hardening Construct	9866	0.04	8	1/25	12/26	$24.57	Yes
FS.93 Lateral Hardening Construct	9866	0.51	98	1/25	12/26	$310.71	Yes
FS.102 Lateral Hardening Construct	9866	0.53	57	1/25	12/26	$321.95	Yes
FS.13584 Lateral Hardening Construct	9866	0.19	14	1/25	12/26	$114.50	Yes
FS.82 Lateral Hardening Construct	9866	0.05	2	1/25	12/26	$28.51	Yes
FS.85 Lateral Hardening Construct	9866	0.28	47	1/25	12/26	$171.29	Yes
FS.87 Lateral Hardening Construct	9866	0.05	2	1/26	12/27	$28.60	Yes
FS.81 Lateral Hardening Construct	9866	0.04	5	1/26	12/27	$23.33	Yes
FS.71 Lateral Hardening Construct	9866	0.09	1	1/26	12/27	$48.11	No
FS.69 Lateral Hardening Construct	9866	0.02	1	1/26	12/27	$13.21	Yes
FS.90 Lateral Hardening Construct	9866	0.08	2	1/26	12/27	$41.09	Yes
REC.2857 Lateral Hardening Construct	9866	0.06	683	1/26	12/27	$35.00	Yes
FS.106 Lateral Hardening Construct	9866	0.03	2	1/26	12/27	$17.34	Yes
FS.80 Lateral Hardening Construct	9866	0.86	93	1/26	12/27	$471.15	Yes
FS.64 Lateral Hardening Construct	9866	0.05	2	1/26	12/27	$26.73	Yes
REC.50 Lateral Hardening Construct	9866	1.88	492	1/26	12/27	$1,024.99	Yes
FS.2541 Lateral Hardening Construct	211	1.80	267	1/25	12/26	$707.26	Yes
FS.2570 Lateral Hardening Construct	211	0.60	92	1/25	12/26	$235.93	Yes
FS.2493 Lateral Hardening Construct	211	0.41	66	1/25	12/26	$160.21	Yes
FS.2800 Lateral Hardening Construct	211	0.52	152	1/25	12/26	$203.24	Yes
FS.2600 Lateral Hardening Construct	211	0.27	58	1/25	12/26	$107.28	Yes

FS.2695 Lateral Hardening Construct	211	0.29	30	1/25	12/26	$114.80	Yes
FS.28386 Lateral Hardening Construct	211	0.33	30	1/25	12/26	$128.72	Yes
FS.2393 Lateral Hardening Construct	211	0.08	21	1/25	12/26	$32.91	Yes
FS.2508 Lateral Hardening Construct	211	0.08	12	1/25	12/26	$29.93	No
FS.2619 Lateral Hardening Construct	211	0.06	17	1/25	12/26	$24.49	Yes
FS.2399 Lateral Hardening Construct	211	0.06	8	1/25	12/26	$24.49	Yes
FS.2254 Lateral Hardening Construct	211	0.06	2	1/25	12/26	$21.74	No
FS.2813 Lateral Hardening Construct	211	0.05	1	1/25	12/26	$17.94	Yes
FS.49189 Lateral Hardening Construct	211	0.20	227	1/25	12/26	$77.50	No
FS.2855 Lateral Hardening Construct	211	0.19	91	1/25	12/26	$74.22	Yes
FS.2122 Lateral Hardening Construct	102	0.53	88	1/26	12/26	$193.18	Yes
FS.2127 Lateral Hardening Construct	102	0.35	60	1/26	12/26	$125.70	Yes
FS.2181 Lateral Hardening Construct	102	0.12	6	1/26	12/26	$44.58	Yes
FS.2257 Lateral Hardening Construct	102	0.36	108	1/26	12/26	$131.58	Yes
FS.2352 Lateral Hardening Construct	102	0.21	14	1/26	12/26	$77.31	Yes
FS.2189 Lateral Hardening Construct	102	0.15	6	1/26	12/26	$55.40	Yes
FS.2704 Lateral Hardening Construct	102	0.21	125	1/26	12/26	$58.55	No
FS.2717 Lateral Hardening Construct	102	0.81	364	1/26	12/26	$74.94	No

Table 12 – Overhead Lateral Hardening 2026 Project Details

6.3 Overhead Lateral Undergrounding

All FPUC feeders were risk ranked in alignment with the Risk Resiliency Model discussed in Section 2 of this report. Circuits were analyzed and prioritized via an algorithm that balances Probability, Response, and Impact. Each feeder circuit was assigned a risk score based on the model's calculation providing FPUC with a prioritized, holistic view of their system. FPUC leveraged the model's recommendation and supplemented it with other quantifiable and non-quantifiable variables of their system at the circuit level to identify the specific Overhead Lateral Undergrounding plan for the first three years of the plan.

The laterals of each targeted feeder were analyzed based on their historical performance over the past five years. The worst performing laterals were prioritized for undergrounding, with overhead hardening considered on a case-by-case basis if undergrounding is determined to be unfeasible, economically or otherwise, for a particular lateral. Project details for year one (2026) of the Plan are shown in the Table 12 below.

Project ID	Feeder ID	Units (Miles)	Total Cust	Start Date	Comp. Date	2026 Cost ($M)	Prior Storm Impact
FS.2640 Lateral Undergrounding Design	209	0.26	103	1/26	12/26	$0.05	No
FS.2645 Lateral Undergrounding Design	209	0.13	64	1/26	12/26	$0.02	Yes
FS.1953 Lateral Undergrounding Design	210	0.05	11	1/26	12/26	$0.01	Yes
FS.2042 Lateral Undergrounding Design	212	0.35	32	1/26	12/26	$0.06	No
FS.2061 Lateral Undergrounding Design	212	0.04	7	1/26	12/26	$0.01	No
FS.2322 Lateral Undergrounding Design	212	0.3	37	1/26	12/26	$0.05	Yes
FS.185 Lateral Undergrounding Construct	9866	1.14	19	1/25	12/27	$0.57	Yes
FS.216 Lateral Undergrounding Construct	9866	2.45	61	1/25	12/27	$1.22	Yes
FS.258 Lateral Undergrounding Construct	9866	1.48	34	1/25	12/27	$0.74	Yes
FS.235 Lateral Undergrounding Construct	9866	0.86	12	1/25	12/27	$0.43	Yes
FS.233 Lateral Undergrounding Construct	9866	0.03	1	1/25	12/27	$0.02	Yes
FS.231 Lateral Undergrounding Construct	9866	0.14	12	1/25	12/27	$0.07	Yes
FS.2003 Lateral Undergrounding Construct	102	0.07	3	1/25	12/27	$0.07	Yes
FS.2069 Lateral Undergrounding Construct	102	0.36	24	1/25	12/27	$0.34	Yes
FS.2274 Lateral Undergrounding Construct	102	0.18	46	1/25	12/27	$0.17	Yes
FS.2329 Lateral Undergrounding Construct	102	0.01	6	1/25	12/27	$0.01	No
FS.2513 Lateral Undergrounding Construct	102	0.63	54	1/25	12/27	$0.60	Yes
FS.2670 Lateral Undergrounding Construct	102	0.15	48	1/25	12/27	$0.15	No

Table 13 – Overhead Lateral Undergrounding 2026 Project Details

7.0 CONCLUSION

FPUC believes that its proposed SPP plan will achieve the desired benefits and objectives outlined in Rule 25-6.030 of "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability" and is therefore in alignment with the Commission's requirements.

FPUC is committed to ongoing fulfillment of the Legislature's directive set forth in Section 366.96, F.S., as well as the Commission's implementing Rule 25-6.030, F.A.C. and believes the aforementioned plan yields important benefits to the FPUC customers and to the State.

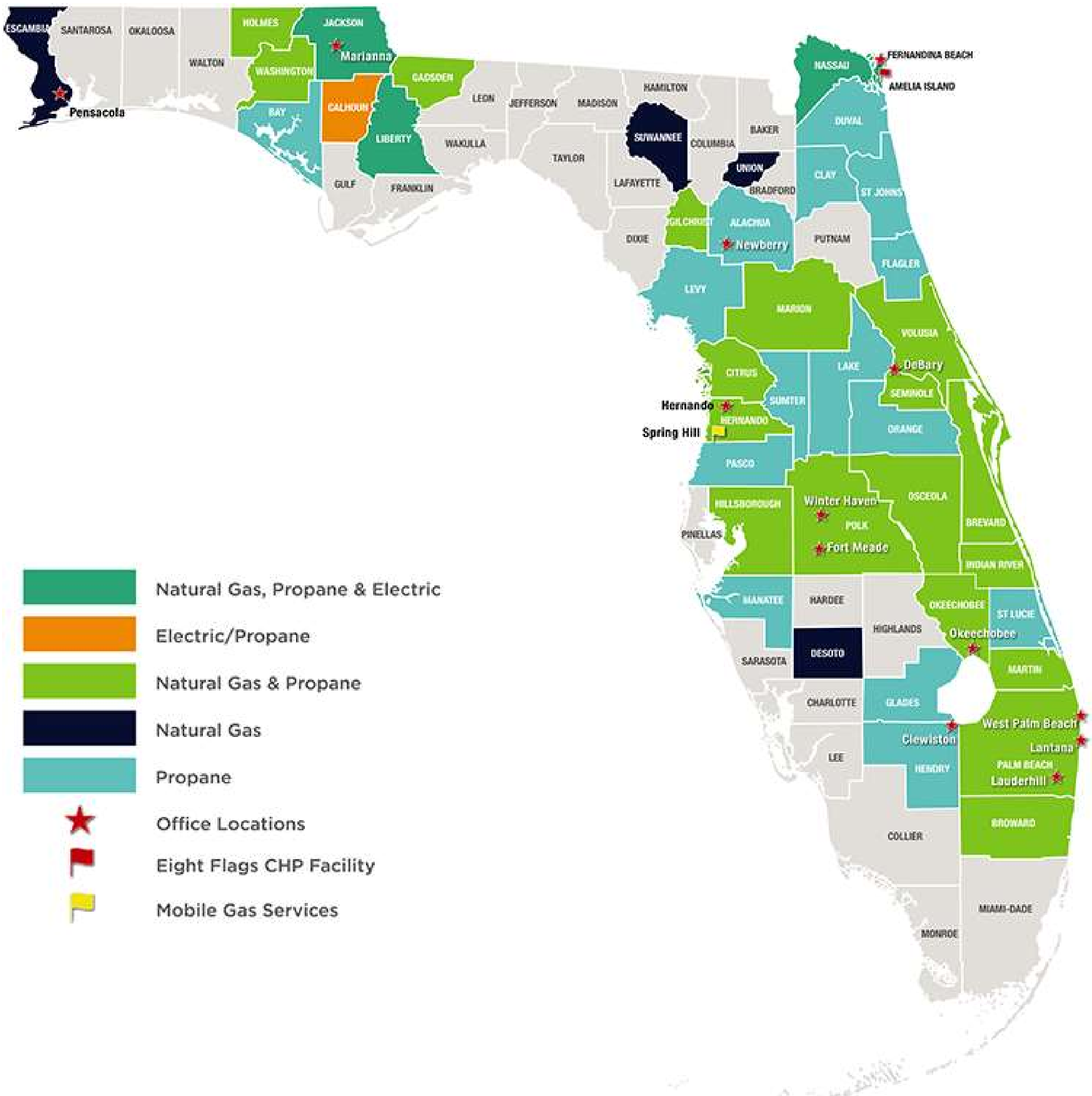
Appendix A

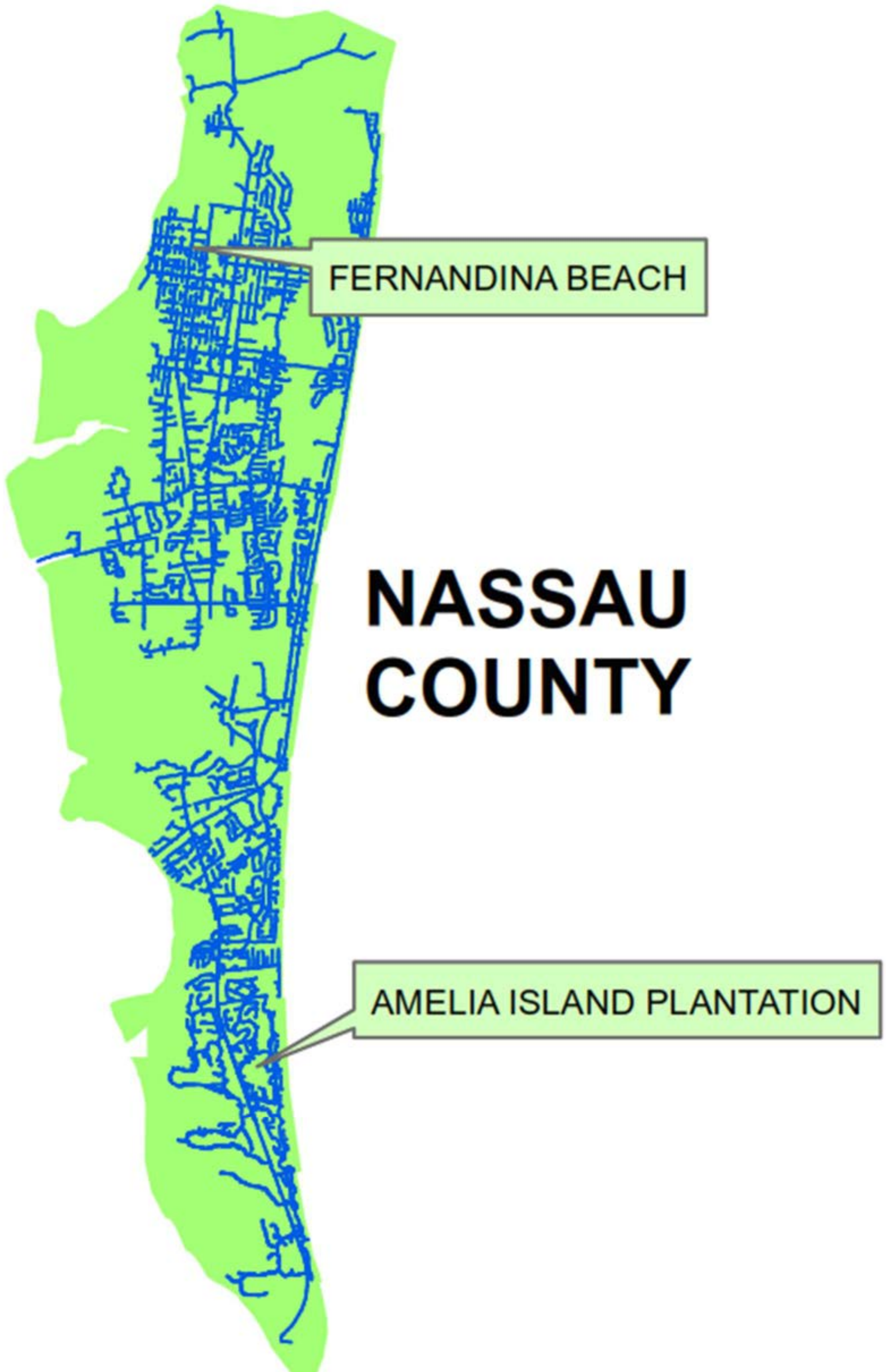
FPUC's 2026 – 2035 Estimated SPP Costs

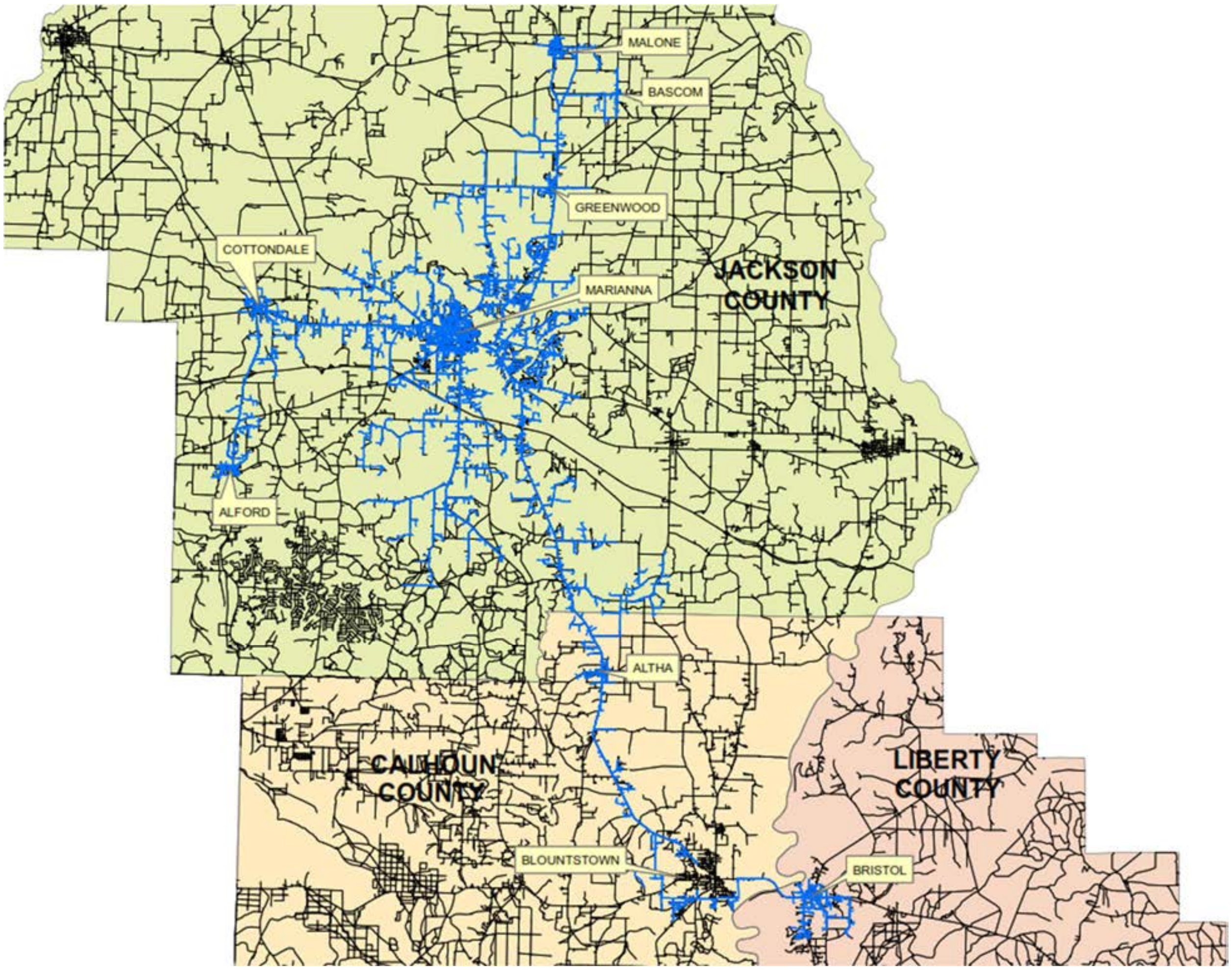
FPUC's 2026-2035 Estimated Storm Protection Plan Costs by Program (in Millions)												
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Distribution - OH Feeder Hardening	Capital	$ 6.52	$ 6.53	$ 6.47	$ 6.45	$ 6.30	$ 6.73	$ 6.50	$ 6.62	$ 6.48	$ 6.46	$ 65.05
	O&M	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 1.30
	Total	$ 6.66	$ 6.66	$ 6.60	$ 6.58	$ 6.42	$ 6.86	$ 6.63	$ 6.75	$ 6.61	$ 6.59	$ 66.35
Distribution - OH Lateral Hardening	Capital	$ 7.77	$ 8.26	$ 7.28	$ 7.66	$ 7.07	$ 7.20	$ 7.70	$ 7.96	$ 7.48	$ 7.79	$ 76.19
	O&M	$ 0.16	$ 0.17	$ 0.15	$ 0.15	$ 0.14	$ 0.14	$ 0.15	$ 0.16	$ 0.15	$ 0.16	$ 1.52
	Total	$ 7.93	$ 8.43	$ 7.43	$ 7.82	$ 7.21	$ 7.34	$ 7.86	$ 8.12	$ 7.63	$ 7.94	$ 77.71
Distribution - OH Lateral Underground	Capital	$ 4.76	$ 5.56	$ 4.77	$ 4.57	$ 5.39	$ 4.57	$ 4.55	$ 4.73	$ 4.79	$ 4.67	$ 48.36
	O&M	$ 0.10	$ 0.11	$ 0.10	$ 0.09	$ 0.11	$ 0.09	$ 0.09	$ 0.09	$ 0.10	$ 0.09	$ 0.97
	Total	$ 4.85	$ 5.67	$ 4.87	$ 4.66	$ 5.50	$ 4.67	$ 4.64	$ 4.82	$ 4.88	$ 4.77	$ 49.33
Distribution - Connectivity and Automation	Capital	$ -	$ -	$ 2.46	$ 2.46	$ 2.46	$ 2.46	$ 2.46	$ 2.46	$ 2.46	$ 2.46	$ 19.68
	O&M	$ -	$ -	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.39
	Total	$ -	$ -	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 20.08
Distribution - Pole Insp. & Replace	Capital	$ 0.50	$ 0.50	$ 0.50	$ 0.50	$ 0.50	$ 0.50	$ 0.50	$ 0.50	$ 0.50	$ 0.50	$ 5.00
	O&M	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 1.90
	Total	$ 0.69	$ 0.69	$ 0.69	$ 0.69	$ 0.69	$ 0.69	$ 0.69	$ 0.69	$ 0.69	$ 0.69	$ 6.90
T&D - Vegetation Management	Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	O&M	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 25.00
	Total	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 25.00
Transmission - Inspection and Hardening	Capital	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 1.20	$ 12.00
	O&M	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.12	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.32
	Total	$ 1.22	$ 1.22	$ 1.22	$ 1.22	$ 1.32	$ 1.22	$ 1.22	$ 1.22	$ 1.22	$ 1.22	$ 12.32
Totals	Capital	$ 20.76	$ 22.05	$ 22.69	$ 22.84	$ 22.92	$ 22.66	$ 22.91	$ 23.47	$ 22.91	$ 23.07	$226.28
	O&M	$ 3.10	$ 3.12	$ 3.13	$ 3.14	$ 3.24	$ 3.13	$ 3.13	$ 3.15	$ 3.13	$ 3.14	$ 31.41
	Total	$ 23.85	$ 25.17	$ 25.82	$ 25.98	$ 26.16	$ 25.79	$ 26.04	$ 26.62	$ 26.04	$ 26.21	$257.68

Appendix B

FPUC Service Area Map


Natural Gas, Propane & Electric
Electric/Propane
Natural Gas & Propane
Natural Gas
Propane
Office Locations
Eight Flags CHP Facility
Mobile Gas Services
ESCAMBIA
SANTAROSA
OKALOOSA
WALTON
HOLMES
JACKSON
Marianna
WASHINGTON
BAY
CALHOUN
GADSDEN
LIBERTY
GULF
FRANKLIN
LEON
WAKULLA
JEFFERSON
MADISON
TAYLOR
HAMILTON
SUWANNEE
COLUMBIA
LAFAYETTE
UNION
BAKER
BRADFORD
NASSAU
FERNANDINA BEACH
AMELIA ISLAND
DUVAL
CLAY
ST JOHNS
PUTNAM
FLAGLER
GILCHRIST
ALACHUA
Newberry
DIXIE
LEVY
MARION
VOLUSIA
DeBary
LAKE
SEMINOLE
CITRUS
SUMTER
Hernando
HERNANDO
Spring Hill
ORANGE
PASCO
OSCEOLA
BREVARD
Winter Haven
POLK
Fort Meade
HILLSBOROUGH
PINELLAS
INDIAN RIVER
MANATEE
HARDEE
OKEECHOBEE
ST LUCIE
Okeechobee
HIGHLANDS
DESOTO
SARASOTA
MARTIN
CHARLOTTE
GLADES
West Palm Beach
Clewiston
Lantana
LEE
HENDRY
PALM BEACH
Lauderhill
BROWARD
COLLIER
MIAMI-DADE
MONROE
Pensacola


FERNANDINA BEACH
NASSAU COUNTY
AMELIA ISLAND PLANTATION


MALONE
BASCOM
GREENWOOD
COTTONDALE
MARIANNA
JACKSON COUNTY
ALFORD
ALTHA
CALHOUN COUNTY
LIBERTY COUNTY
BLOUNTSTOWN
BRISTOL

Appendix C

Davey Resource Group - Trim Cycle and System Assessment; Florida Public Utilities – Mariana

DAVEY
Resource Group

Trim Cycle and System Assessment

Florida Public Utilities—Mariana

November 15, 2019

FLORIDA PUBLIC UTILITIES

PROPOSAL:

TRIM CYCLE AND SYSTEM ASSESSMENT

DAVEY Resource Group

CORPORATE OFFICE:
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1500 North Mantua Street
Kent, OH 44240

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FLORIDA PUBLIC UTILITIES

ACKNOWLEDGEMENTS

The participation, cooperation, background data and current line clearance management information provided by Florida Public Utilities is greatly appreciated. These factors were essential to providing a comprehensive overview of the right-of-way management program.

The following Florida Public Utilities Employees and Davey Resource Group Assessment team and staff participated in or contributed information on this project:

Florida Public Utilities

Clinton Brown
Donnie Tew

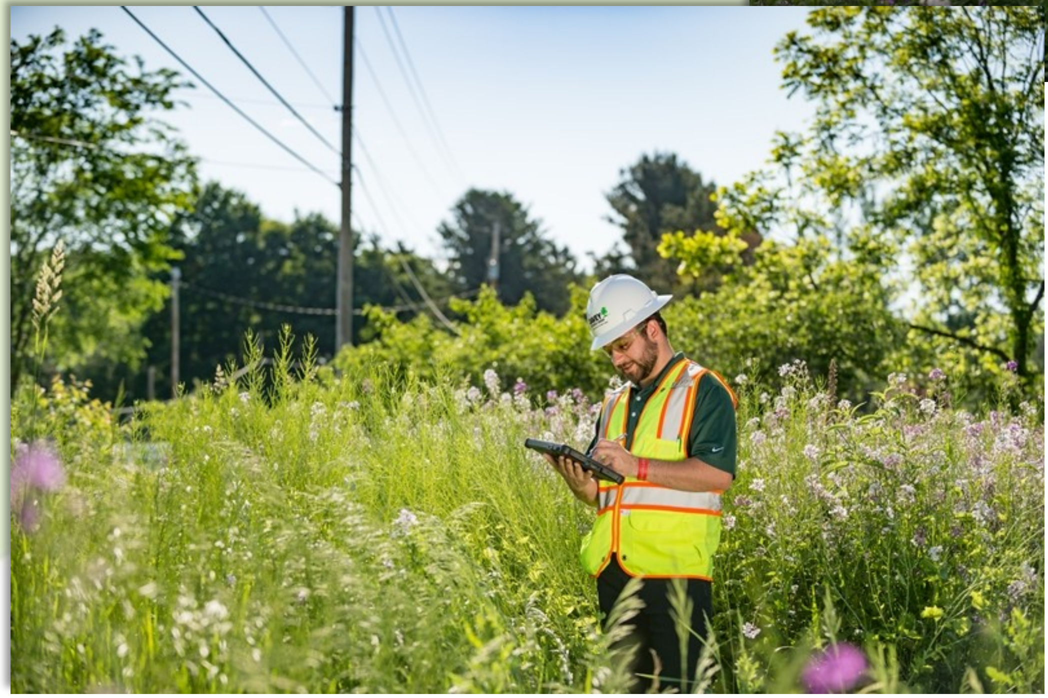
Davey Resource Group

Lindon Deal
Geoffrey Etzel
Scott Anderson
Michael Gross

EXECUTIVE SUMMARY

A comprehensive review and analysis of the existing right-of-way maintenance program and vegetation workload has been conducted for Florida Public Utilities (FPU) This report and analysis are based on information and field observations pertaining to operating procedures for maintenance activities collected by Davey Resource Group's Utility Services personnel during August 2019.

This study was undertaken by FPU to review their present line clearance operation, Vegetation maintenance cycles, and vegetation workload throughout the electric system. This report will provide unbiased comment as to the overall efficiencies of the maintenance program, as well as provide recommendations to improve present operating procedures that will increase productivity, reduce future workloads, and increase reliability throughout the electric system.



STUDY FINDINGS

DAVEY Resource Group

- Hurricane Michael, in September, 2018, has caused lasting impacts to the FPU system
- It is in FPU's best interest to convert to a 4-year, cyclical, circuit based vegetation management plan
- Many Hazard trees exist on the system most of which were created by Hurricane Michael .
- FPU would benefit from additions and clarifications to its Trimming specifications
- A defined herbicide program would assist in maintaining the current workload efficiencies and reduce the occurrence of vine poles

SUMMARY OF PROGRAM RECOMMENDATIONS

- Initiate the implementation of line clearance specifications that will be the foundation for all acceptable line clearance activities.
- Develop a right-of-way post auditing (a Best Management Practice) and inspection process that initiates formal documentation of all acceptable work completed. This process will solidify the responsibility of FPU's vegetation management and ensure entire circuits are maintained appropriately to FPU specifications.
- Implement a complete right-of-way herbicide program that addresses stump treatment as well as species-selective, low-volume application on all right-of-way floors and edge lines.
- Modify the present crew configuration and equipment types to meet the needs of the right-of-way program and deliver cost-effective results
- Move vegetation management program to a 4-year trim cycle

INTRODUCTION

Florida Public Utilities is committed to maintaining uninterrupted service to customers in a safe and environmentally sound manner. This requires compliance with line clearance regulations to ensure public safety, while taking into consideration the best arboricultural practices for managing vegetation. FPU is in a unique situation recovering from Hurricane Michael that occurred one year prior to this review. This event has been catastrophic to the community and to the trees in the area, severely reducing the Tree wire Interface on the FPU system.

METHODOLOGY

Information Gathering

DRG collected information on Florida Public Utilities line clearance program during the month of August 2019. This process included a review of written information which included Line clearance Specifications and last trim dates . Field data was collected by DRG field personnel using the Rover Data collection system, after a two day training period. Quality audits were performed on all work collected in the first week, with a follow up of 10% of the remaining sample sites. Collection protocols were developed prior to training (Appendix A).

Field Assessment

DRG collected detailed information on 62 sample plots of FPU's distribution system in Marianna, Florida. All samples were randomly located across the system. These samples equate to a 10% sampling of the entire 615 FPU circuit miles to ensure a complete sample size. The DRG GIS department used geospatial analytics and remote sensing to determine the actual Tree wire interface on the FPU system to determine actual miles of vegetation workload and ensure DRG did not sample areas with no existing vegetation .

The tree interface is where vegetation is mature enough to cause reliability issues to the FPU system. Currently the overhead electric system has 210 miles of tree interface. DRG ran 62 one mile plots and were able to sample 34% of the actual tree interface in the field during August 2019. A complete listing of tree interface mileage by circuit and phasing can be found in Appendix B.

Sampling Methodology for the Workload Survey

- **Step 1** – Using FPU provided shape files our DRG GIS team used an ARC GIS randomizing tool to ensure non biased random sampling. All sample plots were located on system maps by the GIS team prior to beginning field work.
- **Step 2** – Davey's GIS Department selected consecutive spans segments from the line and pole data, using remote sensing analysis to identify areas of tree wire interface to create 62 sample plots.
- **Step 3 -** Inspection began upstream on the segment and work towards the designated endpoint.
- **Step 4** - Attributes were collected for each sample plot. Attribute definitions are located below in Table 1.
- **Step 5** - Using our Data collection and reporting system, tallies were run for each specific data set and were exported to Excel for further analysis.

Definitions of Data Fields

Average Distance to Conductor	Overall average clearance of vegetation in the sample area	#
Closest to Conductor	Distance to the closest tree in the sample area	# in feet
Species	Species of the tree closes to conductor	Name
Accessibility	Is the work area accessible by a bucket truck or climbing crew? • Accessible as if a truck can be utilized without special permission from property owner • Driveways or areas requiring permission from property owner would be considere4d if inaccessible • If site was 75% accessible and 25% inaccessible, site was considered accessible.	Accessible / Inaccessible
Potential Hazards	Dead, dying or leaning trees. Broken branches over conductors that can be consider a risk to reliability	Yes / No per span
Vine Poles	Any fine that is currently growing on an electric facility (includes poles and guide wires)	# of occurrences in sample
ANSI A300	Were ANSI standards followed during the last trim cycle?	Yes / no by sample area
Land Use	Includes row crops and forested areas	Residential / Commercial / Agricultural
Trapped Trees	Defined as any small tree or brush that has the potential to contact conductors and has its upward growth pushed toward conductors	Yes / no by sample area
Overhang	Trees with canopy or limbs growing over facilities which is less than the minimum specifications. Only overhang that is not compliant with FPU specifications will be documented.	Yes / no by each span
Tree Growth Regulator (TGR)	Are there any trees in the sample area the proper clearance cannot be achieved due to the location of tree? Would it be beneficial for a TGR application?	# of trees in sample area

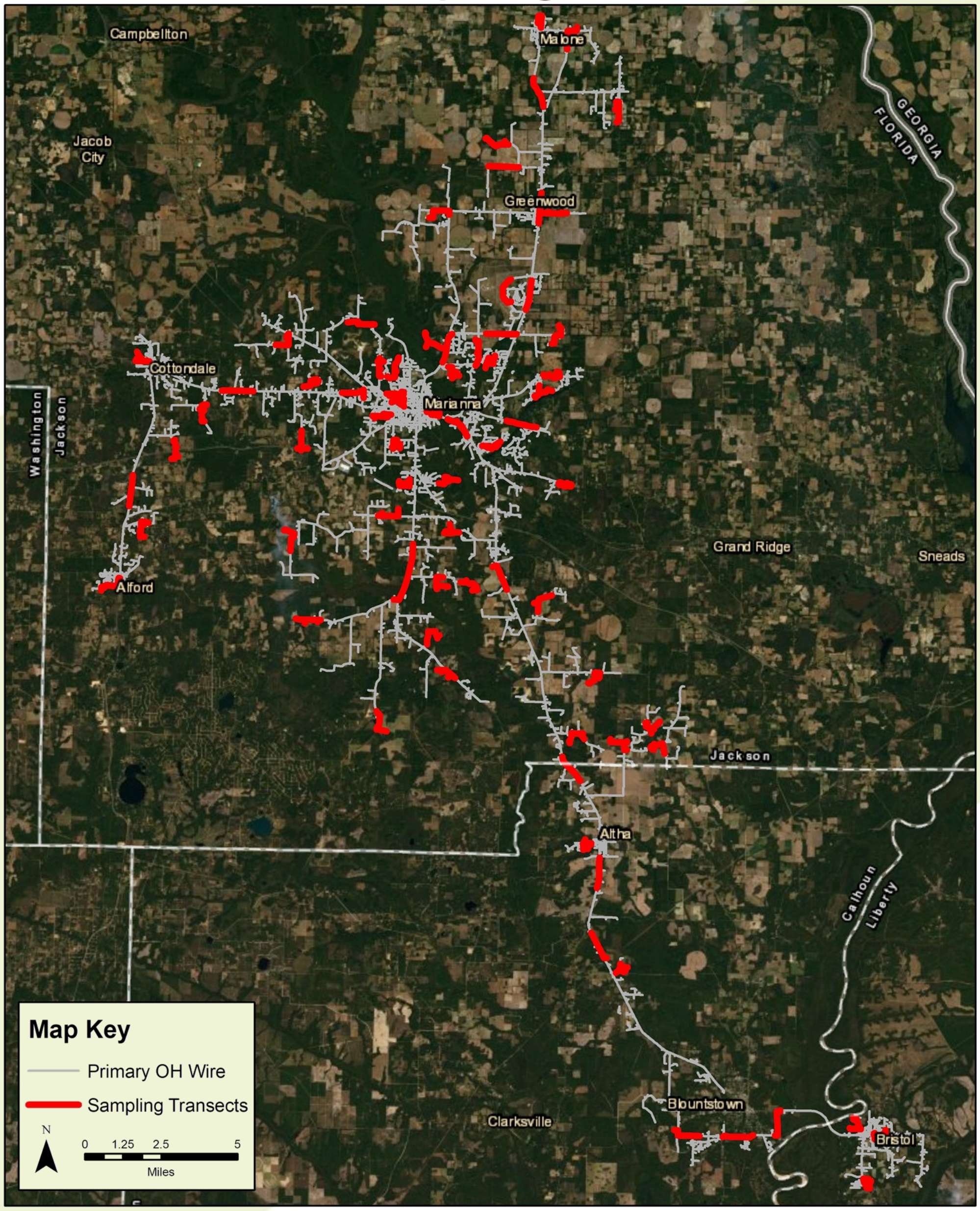
The data fields that were chosen to be collected are strategically designed to capture data relevant to reliability, vegetation workloads, and trim cycle efficacy. To determine the average clearances maintained over time DRG collected the average distance to conductor which represents the bulk of the Tree Interface maintained clearances.

- Pruning trees on a cycle basis (pruning an entire circuit form Substation to last transformer) is efficient, practical and manageable, but leaves the door open for cycle buster trees which grow too fast to maintain clearance throughout the cycle time frame. To identify these "cycle busters" DRG used the data field, Closest to conductor, which identified the significant difference in clearances over time if all trees were trimmed to the same distance from conductor at the same time.
- The data field "species" was collected to identify the actual tree types that can provide a potential reliability challenge in maintaining clearances over time. This data would be used to determine a range of tree species that may be outside of the norm.
- To assist in identifying actual workloads and types of work loads, DRG collected accessibility and land use types to assist in determining the best crew complement to complete the work in the most efficient and cost-effective manner.
- Hazardous Vegetation conditions were documented during the field assessment as well as during the Tree/ Wire Interface evaluation. Hazardous vegetation consists of any dead, dying, diseased, or leaning tree that could cause an interruption to electrical service to FPU customers. Overhanging vegetation is also considered a hazardous condition. Removal of all overhang is recommended when possible.
- Trapped tree data (any brush or small trees that are directly under or are growing directed towards the electric facilities) was collected to determine potential reliability concerns and future work considerations. Most all of these trapped trees are volunteers growing in hedgerows or fence lines. The removal of these trees will reduce future workloads by eliminating trees now rather than pruning them in the future.
- Tree Growth Regulator (TGR) data was collected to determine if its application would be a viable option for maintaining vegetation that proper pruning could not achieve clearance for the given cycle length or removal of vegetation was not an option, and due to the 2018 Hurricane Michael and the devastation to the trees we found that there is not enough candidates available to be a cost effective and efficient way to manage any of your tree load.
- Vines growing on any pole or guide wire pose a threat to electric facilities. Removal of vines can be accomplished manually but a combination of manual and chemical remove is advised for longer term control.
- ANSI A300 is the National Standard utilized by Utilities for proper pruning techniques. Adherence to these standards will assist in maintaining proper clearance of vegetation for the length of the cycle and promote the long term health of the trees.

Distribution of Data Collected

This map provides an overview of the sample areas and their even distribution across the FPU system. Tree/Wire interface data was used in excluding areas that do not require line clearance activities. Sample plots are placed randomly across the system in location with Tree/Wire Interface without bias to accessibility or work type.

Data Sampling Transects



FINDINGS

Tree Interface and Hurricane Michael

Tree interface is described as areas that will require routine maintenance of vegetation on one or both sides of the conductor by line clearing contractors. Through geospatial analytics, remote sensing and field verification it is determined that of the 615 FPU overhead conductor miles, 210 miles or 34% have tree interface. The small percent of tree interface on the FPU system can be accounted for, in some degree, by the effects of the 2018 Hurricane. This storm has leveled many forested acres in the FPU territory and reduced the remaining standing healthy trees considerably. One of the lasting effects of this storm is the existence of still standing Hazard trees that have been weakened or damaged.

Most utility vegetation management programs evaluate workload using circuit mileage; however, this fails to account for urban, agricultural, or industrial areas that do not present tree interface with utility assets. While these locations require continuing floor maintenance to address incompatible vegetation, they do not pose a current risk to utility assets.

Tree interface mileage, often a fraction of the total circuit miles, is a far more reliable source of information on which to inform data-driven forecasting, decision making, and resource management.

Tree interface miles does not include low undergrowth or brush under the conductors or facilities. This number would exclude any herbicide or mowing activities.

Substation	Circuit	Status	Total OH Miles	Tree Interface Miles	Tree Interface %
Altha	9952	STANDING	51.04	15.18	30%
Altha	9972	STANDING	13.75	2.85	21%
B-Town	9882	STANDING	54.12	17.21	32%
Caverns	9722	STANDING	13.94	4.46	32%
Caverns	9732	STANDING	6.3	2.46	39%
Caverns	9742	STANDING	61.06	19.83	32%
Caverns	9752	STANDING	4.21	0.24	6%
Marianna	9782	STANDING	3.85	1.45	38%
Chipola	9932	STANDING	32.14	14.81	46%
Chipola	9942	STANDING	62.13	15.6	25%
Chipola	9982	STANDING	52.366	19.43	37%
Chipola	9992	STANDING	15.63	5.69	36%
Marianna	9512	STANDING	18.08	6.3	35%
Marianna	9854	STANDING	107.02	33.8	32%
Marianna	9866	STANDING	79.7	30.1	38%
Marianna	9872	STANDING	39.65	19.8	50%
		STANDING	614.98	**209.23**	**34%**

Tree Wire Interface Miles by Phasing

		TWI Miles	Total Miles	% TIF
Single Phase	Bucket	92.52		
	Manual	55.83		
		148.35	390.45	37.99%
Two Phase	Bucket	8.8		
	Manual	2.81		
		11.61	30.32	38.29%
Three Phase	Bucket	34		
	Manual	16.1		
		50.1	194.24	25.79%
	Totals	210.06	615.01	34.16%

Tree Wire Interface Miles by work type

Based on the data from sample plots shown in the table below, FPUC has approximately 210 tree interface miles. 135.32 are accessible by bucket (64%) and 74.74 is non-accessible or climbing work(36%). Knowledge of the amount of manual and bucket accessible work will assist in determining the best crew complement to complete the work on a cyclical basis. It is best to normalize the contract crew complement from year to year. A normalize crew compliment will keep trained employees long term which will keep them engaged and take ownership in the line clearance program at FPUC.

	Miles	% of System
Manual	74.74	12%
Bucket	135.32	22%
Total Miles	210.06	34%

Accessibility of Vegetation Work

Accessibility by Sample Plot

Bucket Accessible areas across the sample area is at 87%. 83% single phase is accessible and approximately 100% of three phase. Accessibility was determined by majority of work in sample area. As discussed previously, this will assist in determining the appropriate crew complement to complete the assigned work in the most efficient and cost-effective manner. For Example, crew complement should be 2 - 3-man buckets, 1 manual crew, and a mechanical trimmer. In this case work group shall have the ability to complete designated work in inaccessible areas.

1Phase	Sample Plots	% of Accessibility
Acc	35	83%
Inaccessible	7	17%
3 Phase	20	
Acc	20	100%
Inaccessible	0	

Clearances

Average Distance All Phasing

Across the system, 68% have more than 6FT of clearance and of which 50% have over 10ft of clearance. As seen in table 4, an estimated 6% of vegetation has 5 to 6 ft clearance, 10% has 6 to 7 ft clearance, 8% has 8 to 9, and 50% has more than 10ft of clearance While only 26% (one quarter) have less than 4ft. The percentage of close trees can be potentially attributed to ANSI-A300 compliance and/or faster growing tree species known as "cycle busters".

This shows that 74% of the vegetation is holding cycle, in compliance, and is an indicator of cycle length. Overall clearance across FPU system is acceptable. With only 26% averaging less than 4 ft of clearance, this indicates a 4-year cycle is obtainable.

Average Distance All Phasing	Locations	% of Clearance in Sample Areas	
1 to 2	8	13%	26%
3 to 4	8	13%	
5 to 6	4	6%	
6 to 7	6	10%	
8 to 9	5	8%	68%
10+	31	50%	
Total	62		

Average Distance by Phase

FPU is currently on a Three year cycle on 3 Phase and Six year on Single phase. As you can see from this data, the shorter cycle on three phase is maintaining the clearance over the duration of the cycle. While this is the case on three phase, conditions on single phase are much closer. The longer the cycle length, the greater risk for tree/wire contact and vegetation related outages. By moving the circuit bodies to a 4 year cycle and better adherence to line clearance specifications, FPU will be better able to maintain proper clearances and reduce the number of preventable outages due to vegetation.

Average Distance by Phase

Phase	Counts	% of Counts	1 to 2	3 to 4	5 to 6	6 to 7	8-9	10+	Total Occurrence Per Phase
Single phase	42	68%	6	8	2	6	3	17	42
Single All Samples %			10%	13%	3%	10%	5%	27%	
Single Only %			14%	19%	5%	14%	7%	40%	
Three Phase	20	32%	2	0	2	0	2	14	20
Three All Samples %			3%	0%	3%	0%	3%	23%	
Three Only %			10%	0	10%	0%	10%	70%	

Closest Vegetation to Facility by Distance

Average clearance across the FPU system is generally considered acceptable. However, 50 of the 62 samples have vegetation within 2 ft of energized conductors. This was due mainly to trees that had not been trimmed and not regrowth from previous trimming. Complete circuit trimming would significantly reduce the occurrences of trees within 2 foot of conductors.

Closest Clearances	
0	20
1 to 2	30
3 to 4	7
5 to 6	1
6 to 7	1
8+	3
	62

The closest tree species in 23 of the 50 locations with vegetation within 2 ft of conductors have been identified as Oaks. Oak trees are generally a species with a slower growth rate and maintain clearances for the duration of the trim cycle when trimmed properly and to FPU line clearance specifications. Adherence to line clearance specifications would significantly reduce the frequency of Oaks as closest to conductors.

All phase	Clearance	Count	Species
	0	20	9 -oak
	1-2	30	14 -0ak

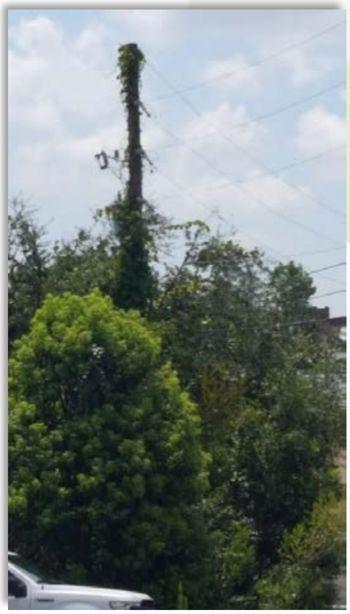
The FPU system has equal diversity of rural and residential/ commercial locations in the sample areas. Of the sample locations, 55% are located in agricultural areas while 35% and 10% and in residential and commercial areas respectively. Estimated over the system this equates to 338 miles in Agricultural areas, 215 residential and 62 in commercial. Agricultural areas allow for higher usage of mechanical equipment and implementation of a robust herbicide program.

Land Use		
Total records	62	
Ag	34	55%
Commercial	6	10%
Residential	22	35%

Occurrences of Vines by Phasing and Land Use

190 vine locations have been identified in the 62 sample areas. Of these locations, 148 are located on single phase and 42 are on three phase. Vine locations are spread evenly across the system. Residential areas account for 91 occurrences (48%), Agriculture account for 84 (44%) and commercial had 15 (8%).

FPU system has and average of 3.06 vines per mile or estimated 1882 locations. This data shows the importance of the implementation of a Vine program on FPU System. A vine program can be easily integrated into a robust herbicide program.



Vines	
1Phase	148
Ag	66
Res	82
Com	0
3 Phase	42
Ag	18
Res	9
Com	15
Total	**190**

Scheduling for Cycle

As discussed, there are 210 miles of existing tree interface on the FPU system. On a four-year cycle this would require vegetation trimming/removals on 52.5 miles of tree interface per year. In the table below (Table?) the tree interface is broken down into years, months, weeks then days to assist in determining actual workload and manpower requirements. This chart further breaks down the tree interface into bucket and manual to determine the number of tree crew requirements.

	System	Miles	Miles	Miles	Miles	Linear	Estimated Trees	Man Hours	Tree Crew
	Tree Miles	Per 4-year Cycle	Per Month	Per Week	Per Day	Feet Per Day	Average 20 ft Width	1 Hour Per Tree	Personnel
Bucket	135.32	33.83	2.82	0.68	0.14	714.49	35.72	35.72	4.5
Manual	74.74	18.69	1.56	0.37	0.07	394.63	19.73	19.73	2.5
Totals	210.06	52.52	4.38	1.05	0.21	1109.12	55.46	55.46	6.9
* Based on a 50 week work year									

ANSI A300 Compliance

ANSI compliance		
No	14	23%
Yes	48	77%

Ansi-A300 is the National Standard for proper trimming techniques. Compliance with ANSI-A300 is essential. 77% of samples are compliant while 23% is not. Ansi-A300 standards do not state any clearance specification but proper pruning techniques. If proper pruning techniques are used, they will assist in maintaining trim cycles and not adversely affect the health of the trees being maintained. Compliance with this standard should be improved if moving to a 4-year cycle. To assure compliance, Auditing of completed line clearing activities is recommended.

Overhang

Overhang	62	Miles Inspected	
Total	40		
1 phase	32	42	76.19%
3 phase	8	20	40.00%

Documented overhang is vegetation directly above conductors that is not in compliance with FPU line clearance specifications. Thirty-two of the 40 single phase samples (76%) and 8 of the twenty 3-phase (40%) had at least one occurrence in the sample area. Compliance with ANSI-A300 standards and cycle-based trimming would result in a reduction in occurrences and vegetation related outages.


Hazards

Identified hazards are identified as any dead, dying, leaning tree that could make contact with conductors and cause an interruption to electrical service. 73% of the single phase and 60% of the 3 phase samples have at least one occurrence of a hazard in the sample area. The high amount of hazards is impart but not solely due to Hurricane Michael in September, 2018. Implementation of a hazard tree program is recommended to reduce the probability of an interruption in electrical service due to identified hazards.

Hazards	Site	Occurrences			% with Haz
Locations	62	43	Acc	In-Acc	
1 Phase	42	31	26	5	73.81%
3 Phase	20	12	12	0	60.00%

Storm Damage

While conducting the Tree/Wire Interface assessment, The DRG GIS dept has identified additional areas with storm damage have been identified from aerial photography. An additional 58.46 miles have been determined to have "storm damage". Storm Damage areas is defined as areas with trees that have broken tops, leaning or damaged in other ways.

While this mileage is in addition to the TIF miles, It represents the damage caused by Hurricane Michael in 2018. While all of the areas may not have vegetation deemed hazardous to the electrical system, It represents the widespread damage due to Hurricane Michael in 2018.

Substation	Circuit	Status	Total Feet	Total Miles
Altha	9952	STORM DAMAGE	7725	1.46
Altha	9972	STORM DAMAGE	889	0.17
B-Town	9882	STORM DAMAGE	13259	2.51
Caverns	9722	STORM DAMAGE	4866	0.92
Caverns	9732	STORM DAMAGE	112	0.02
Caverns	9742	STORM DAMAGE	3804	0.72
Caverns	9752	STORM DAMAGE	550	0.1
Chipola	9782	STORM DAMAGE	30	0.01
Chipola	9932	STORM DAMAGE	12186	2.31
Chipola	9942	STORM DAMAGE	60918	11.54
Chipola	9982	STORM DAMAGE	32805	6.21
Chipola	9992	STORM DAMAGE	2126	0.4
Marianna	9512	STORM DAMAGE	3653	0.69
Marianna	9854	STORM DAMAGE	120005	22.73
Marianna	9866	STORM DAMAGE	36749	6.96
Marianna	9872	STORM DAMAGE	8972	1.7
		STORM DAMAGE		58.46

Tree Growth Regulators (TGR)

Tree growth regulators (TGR) are a way to reduce the growth rates in vegetation. TGR's are an option whenever a tree cannot be maintained to specifications and removal is not an option. Of the 62 miles on the assessment, only 5 trees were identified as TGR candidates. All five locations are on lower priority 1 phase lines in Residential and Agricultural areas.

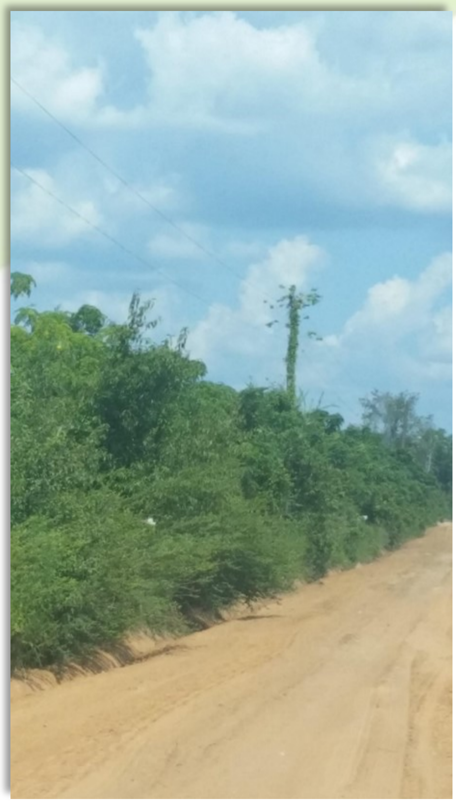
Totals	Locations
1 Phase	5
3 phase	0

It is estimated that there would be only 20 TRG candidates across the system. The addition of a TGR program is not a cost-effective option for FPU due to low number of locations, set up and equipment and labor intensive.

Trapped Trees

Trapped Trees	TOTALS	Res	Com	Ag
Total Locations	40	17	4	19
All Phasing	62	27.42%	6.45%	30.65%
3 Phase	11	3	4	4
1 phase	29	14	0	15

Trapped trees are any small tree or Brush that has the potential to contact conductors and has its upward growth pushed toward conductors. Trapped trees are excellent candidates for removal. Removal of trapped trees can reduce future workloads by number of trees to trim and disposal of debris generated for trimming activities. Trapped trees can be addressed by manual removal, mowing operations or herbicide application. If trapped trees are removed manually or by mowing operation, it is recommended to follow up with an herbicide stump treatment to minimize future regrowth and future workloads.



Most occurrences with Trapped Trees are mainly concentrated in Residential (27%) and Agricultural (31%) areas. Most occurrences of trapped trees have not been planted by property owners. They are volunteers that have been naturally seeded. With proper notification of residential customer, most all would be removed. In agricultural areas, many are located along fence lines and edge of right of ways and should be removed during routine maintenance.

A strong post work audit should be completed to assure all trapped trees have been addressed.

Findings

Due to Hurricane Michael, FPUC has the opportunity to move to a 4 year cycle on all facilities. With moving to a 4 year cycle, we recommend the following:

Implementation of a Hazard tree Program. Michael was a category 5 hurricane when it made landfall on October 10, 2018. At landfall, Michael had sustained wind speeds of 160 mph. The path of the storm crossed directly over FPU service territory in Marianna, Florida.

Sustained winds at Marianna airport recorded at 102 mph, gusting to 122 mph. Due to Hurricane Michael, the FPU service territory has many potential hazardous trees across the system. Of the 62 sample areas, 43 have potential hazards. 73% of the 1 phase plots and 60% of the 3 phase have hazards.

In creating a hazard tree program, it must be determined what is the acceptable risk and redesign of these specifications.

Reduction of mowing program and increase in herbicide application. Mowing creates more incompatible vegetation with higher densities prior to mowing. The implementation of an expanded herbicide program will promote grasses instead.

An herbicide program will also assist with control of vines across the system. Of the 62 sample plots, 190 pole locations have been identified with vine conditions.

Circuit Based Trimming. Overall clearance across the FPU system is acceptable. While the average clearance is acceptable, 80% of the sample areas have vegetation within 2ft of conductors. Many of the sample areas had recent trimming activities but not fully completed. It is recommended to move to a circuit based approach to line clearance. This would be the assignment of complete circuits to the line clearing contractor. This approach would allow FPU to achieve and maintain a designated cycle for each circuit. Determining the order of each circuit would be determined based on a matrix of customer count, critical infrastructure and vegetation caused customer interruptions.

Tree/ Wire Interface findings. Of the 615 miles of OH conductors, only 210 miles require routine tree trimming. If wanting to move to a 4 year cycle, FPU will only need to trim an average of 52.5 miles per year. That is roughly 12 miles of 3 phase and 40 miles of laterals annually.

TRIM CYCLE RECOMMENDATIONS

DAVEY Resource Group

DRG recommends FPU Marianna moving to a 4 year vegetation maintenance cycle. This recommendation is based on the current mileage needed to be maintained annually according to the Tree/Wire interface data.

DRG recommends the trim cycle laid out in Chart below. The trim cycle is based on the normalization of miles, customers affected and critical customers determined by FPUC.

Substation	Circuit	1 Ph	2Ph	3Ph	Total OH Miles	Tree Interface	Cycle	Cust Count	% OF System
Marianna	9512 Railroad	6.82	1.16	10.11	18.09	6.3	1	609	
Caverns	9722 Dogwood Height	10.53	0	3.4	13.93	4.85	1	290	
Caverns	9742 Greenwood	34.83	1.63	24.59	61.05	20.21	1	1113	
Marianna	9782 Family Dollar	0.72	0	3.13	3.85	1.45	1	23	
Marianna	9872 Hospital	30.02	2.76	6.87	39.65	19.8	1	767	
					136.57	**52.61**		**2802**	**22.20%**
Caverns	9732 Prison	0.55	0	5.75	6.3	2.46	2	51	
Caverns	9752 Industrial Park	0.28	0	3.94	4.22	0.24	2	43	
Marianna	9866 Cottondale	54.11	2.89	22.7	79.7	30.1	2	1424	
Chipola	9982 College	23.95	6.47	21.95	52.37	19.58	2	1132	
					142.59	**52.38**		**2650**	**23.20%**
Chipola	9942 Hwy 90e	40.15	2.65	19.34	62.14	15.6	3	726	
Altha	9972 Blountstown	5.96	0.19	7.61	13.76	2.85	3	192	
Marianna	9854 South Street	85.16	4.02	17.84	107.02	33.8	3	1908	
					182.92	**52.25**		2826	**29.70%**
B-Town	9882 Bristol	34.4	3.39	16.34	54.13	17.21	4	**1034**	
Chipola	9932 Indian Springs	17.43	3.9	10.81	32.14	14.81	4	931	
Altha	9952 Altha	39.45	0.29	11.3	51.04	15.18	4	859	
Chipola	9992 Hwy 90w	6.1	0.96	8.57	15.63	5.69	4	921	
					152.94	**52.89**		**3745**	**24.70%**
Totals					**615.02**	**210.13**		**12023**	

To complete the annual trim cycle, it is recommended the utilization of three aerial lift trucks with chippers. Of the three, two shall have the crews with the capabilities of climbing trees as needed.

For the completion of customer tickets and emergency work, it is recommended a fourth aerial truck be utilized until the first four year cycle has been completed.