BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20220048-EI

Review of Storm Protection Plan,
pursuant to Rule 25-6.030, F.A.C.,
Tampa Electric Company.
_________________________________/

DOCKET NO. 20220049-EI

Review of Storm Protection Plan,
pursuant to Rule 25-6.030, F.A.C.,
Florida Public Utilities Company.
_________________________________/

DOCKET NO. 20220050-EI

Review of Storm Protection Plan,
pursuant to Rule 25-6.030, F.A.C.,
Duke Energy Florida, LLC.
_________________________________/

DOCKET NO. 20220051-EI

Review of Storm Protection Plan,
pursuant to Rule 25-6.030, F.A.C.,
Florida Power & Light Company.
_________________________________/

VOLUME 4
PAGES 597 - 793

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN ANDREW GILES FAY
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Wednesday, August 3, 2022

TIME: Commenced: 9:30 a.m.
Concluded: 4:56 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
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I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMITTED
12	As identified in the CEL		613
16-17	As identified in the CEL		634
19	As identified in the CEL		634
21-51	As identified in the CEL		634

P R O C E E D I N G S

(Transcript follows in sequence from Volume 3.)

CHAIRMAN FAY: All right. Ms. Keating, when you are ready, we will move on to FPUC's witness.

MS. KEATING: Thank you, Mr. Chairman.

Florida Public Utilities Company calls Mark Cutshaw to the stand.

Whereupon,

P. MARK CUTSHAW

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MS. KEATING:

Q Mr. Cutshaw, could you please state your full name for the record?

A My name is Mark Cutshaw.

Q And you were here yesterday and have been previously sworn, is that correct?

A That's correct.

Q Okay. Please tell us by whom you are employed and in what capacity.

A I am employed by Florida Public Utilities Company as the Director of Generation.

Q And did you cause to be filed in this proceeding 15 pages of direct testimony on April 11th, 2022?

A Yes, I did.

Q Do you have any changes or corrections?

A No, I do not.

Q Okay. And if I asked you those same questions, would you still have the same answers?

A Yes, I would.

MS. KEATING: Okay. Mr. Chairman, we would ask that Mr. Cutshaw's direct testimony be inserted into the record as though read.

THE WITNESS: Show it inserted.

(Whereupon, prefiled direct testimony of P. Mark Cutshaw was inserted.)

Before the Florida Public Service Commission

Direct Testimony of P. Mark Cutshaw

On Behalf of

Florida Public Utilities Company

Docket 20220049-EI

(Consolidated Dockets 20220048, 20220049, 20220050, and 20220051)

I. Background

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw. My business address is 208 Wildlight Avenue, Yulee, Florida 32097.

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 2020, I moved into my current role as Director, Generation Development.

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 and numerous dockets for Fuel and Purchased Power Cost Recovery. Most recently, I provided testimony in Docket No. 20190156-EI, in the Limited Proceeding to recover storm cost caused by Hurricane Michael.

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

A. The purpose of my testimony is to provide an overview of the 2022 – 2031 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 contains the details related to the FPUC SPP.

II. <u>Overview of the FPUC SPP</u>

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.

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." 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. 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, we asked the Commission to allow FPUC to defer its filing an additional year, which would put us back 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 has continued to operate under its current Storm Hardening Plan until now, the next scheduled SPP filing.

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

A. FPUC, with the assistance of Pike Engineering, has developed a Storm Protection Plan that will strengthen the utility's electric utility infrastructure to withstand extreme weather conditions. Key aspects of the SPP promote 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.

Q. Were there unique considerations in the 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 geographical 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 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 newly proposed Programs which are grounded on a methodology of resiliency risk scores across FPUC's Distribution system.

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

A. After extensive analysis, the primary new programs of the FPUC SPP focus on Overhead Feeder Hardening, Overhead Lateral Hardening, Overhead Lateral Undergrounding, Transmission & Substation Resiliency, and Future System Enhancements. FPUC also includes, with slight modifications, previously approved programs for Distribution Pole Inspections and Replacements, Transmission System Inspection and Hardening and Vegetation Management programs which are part of the current Storm Hardening Plan approved for FPUC. A brief description of these plans are as follows.

<u>Overhead Feeder Hardening</u>

The Overhead Feeder Hardening program will upgrade backbone overhead lines.

<u>Overhead Lateral Hardening</u>

The Overhead Lateral Hardening program will upgrade existing overhead key lateral lines.

<u>Overhead Lateral Undergrounding</u>

The Overhead Lateral Undergrounding program will underground lateral lines in certain areas.

<u>Distribution Pole Inspections and Replacements</u>

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.

<u>Transmission System Inspection and Hardening</u>

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 & Substation Resiliency

The Transmission & Substation Resiliency program will construct an additional 138 KV transmission line, upgrade one 69 KV transmission line and construct one substation to improve the electrical resiliency to Amelia Island.

Future System Enhancements

The Future System Enhancements Program will address new technology additions for the transmission and distribution system.

Vegetation Management Program

The Vegetation Management Program will continue to address vegetation management activities related to FPUC transmission and distribution lines, though under a new 4-year cycle.

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 is relatively small in comparison to other utilities, our customers 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. 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. What cost recovery impact will be associated with the FPUC SPP and is it included in this filing?

A. The cost recovery filing for FPUC's expenditures under its SPP will be submitted for approval of cost recovery under the Storm Protection Plan Cost Recovery Clause ("SPP CRC"), pursuant to Rule 25-6.031, FAC., and will be filed in May 2022, in Docket No. 20220010-EI. As this is FPUC's initial SPP filing, the actual cost recovery for FPUC's SPP will not begin until cost recovery factors are established in that proceeding. Projected SPP costs that will be submitted for consideration in that proceeding will involve the implementation of the above-listed programs. To the extent there are existing programs that will be continued from the Company's existing Storm Hardening Plan, there may be some costs associated with these programs already included in the base rates approved for the Company during its last rate proceeding. These costs will be identified at the time of SPP cost recovery filing such that only incremental investments are included for SPP CRC as required by Rule 25.6.031, F.A.C.

Specifically, the Overhead Feeder Hardening, Overhead Lateral Hardening, Overhead Lateral Undergrounding, Transmission & Substation Resiliency and Future System Enhancements are new programs, which will be included in the Company's filing for cost recovery in Docket No. 20220010-EI. The Vegetation Management, Distribution Pole

Inspections and Replacements and Transmission System Inspection and Hardening programs currently exist and thus, will continue to be primarily covered through base rates, although some incremental cost increases for these programs due to modifications under the SPP will be included in FPUC's request for cost recovery. The incremental cost is associated with additional resources that will be required to implement the modification of these programs. It is possible, however, that as the FPUC SPP is refined there may be additional changes in the programs which may require modifications which will impact the recovery mechanism in the future.

Q. Will there be any cost impact due to internal staffing changes that will result from the development and administration of the FPUC SPP which is included in this filing?

A. Yes. Included in the FPUC SPP filing is one Full Time Equivalent (FTE) position that will be responsible for continued development, monitoring and administration. This position will be responsible for the FPUC SPP projects, scheduling and cost control/data collection necessary for the success of the program as well as documentation necessary for the Cost Recovery for the FPUC SPP.

III. Storm Protection Plan Programs

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.

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 National Electric Safety Code (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(d) of the NESC, has been adopted. Enhancements and incremental cost impacts to the Distribution Pole Inspection & Replacement program will look to accelerate the replacement of wood Distribution poles that have been identified and scheduled for replacement following their cyclical inspection.

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

A. This 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. Enhancements to the Transmission Wood Pole Replacement program will look to accelerate 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 & Substation Resiliency Program.

A. The Transmission & Substation Resiliency program details the construction of an additional 138 KV transmission line, the upgrade of one 69 KV transmission line, and the construction of one substation to improve the electrical redundancy and resiliency to Amelia Island. Amelia Island is currently served by an FPUC-owned, dual circuit 138 KV transmission line that extends from an off-island interconnection point with the FPL transmission system across the Amelia River. This dual circuit is constructed along the same right-of-way and on the same structures (mixture of concrete poles, steel poles and steel towers) over the entire length and is connected to a transmission substation on Amelia Island. The location of this transmission system makes access to it very challenging, which could result in an extended outage to the Island should it be damaged or destroyed. Thus, a redundant transmission line is required to ensure continued reliability of service to the Northeast Division.

Additionally, this program addresses the necessity to upgrade an existing 69 KV transmission line from an existing paper mill on Amelia Island that has cogeneration capacity. This upgrade is necessary to access the full generation capabilities for emergency purposes and will also necessitate the installation of an interconnecting substation.

Ultimately, this enhanced interconnection will provide additional resiliency and redundancy to FPUC customers on Amelia Island.

Q. Please describe the Future System Enhancement Program.

A. After weighing the proven reliability gains and the costs, FPUC has included under this Program consideration of distribution automation or "smart grid" type technology, which leverages technology to detect a fault in the system, automatically isolate the faulted section, and reroute power to restore power to affected areas of the grid. A Supervisory Control and Data Acquisition (SCADA) system is a key software tool that enables either a Distribution System Operator or software systems such as Distribution Management System (DMS) to initiate commands for the remote control of grid devices. The configuration of FPUC's current SCADA system does not allow for this capability; thus, this aspect of FPUC's SPP contemplates analysis of the possible strategic benefits of investing in Distribution Automation systems in future programs to be included in later iterations of FPUC's SPP.

Q. Please describe the Vegetation Management Program

A. Under the SPP, FPUC proposes to modify its current program to accelerate towards a four-year vegetation management cycle on main feeders and laterals on the system. FPUC has completed a study regarding possible changes to its vegetation management cycle and has determined that this four-year cycle is a more efficient and cost-effective trim cycle than the existing three-year feeder and six-year lateral trim cycle that will also reduce outages and restoration times during extreme weather events.

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 of the FPUC SPP is provided in Sections 3.0, 5.0 and 6.0 of FPUC's SPP if 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 estimate 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 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 2022 – 2031 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 current operating environment.

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 that a 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 proposed SPP builds on what has 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. The SPP also contemplates the further analysis and development of additional programs 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.

BY MS. KEATING:

Q Mr. Cutshaw, were you also involved in the preparation, and did you cause to be filed Exhibit PMC-1, which is FPUC's storm protection plan?

A Yes, I was.

MS. KEATING: Mr. Chairman, I believe that has already been marked as Exhibit 12.

CHAIRMAN FAY: Correct.

BY MS. KEATING:

Q Mr. Cutshaw, did you prepare a summary of your direct testimony?

A Yes, I did.

Q Would you please go ahead and present that?

A Good afternoon, Commissioners. Thank you for the opportunity to address you today.

The purpose of my direct testimony is to provide information on the development of the Florida Public Utilities Company storm protection plan, which I am sponsoring.

This is our first storm protection plan, and we worked with Pike Engineering to develop a plan that, consistent with rule, will protect our critical infrastructure, and ultimately reduce restoration costs and outage times associated with extreme weather events.

Our proposed storm protection plan takes into consideration the geographical differences in two distinct service territories, as well as the historical reliability performance in both extreme and non-extreme conditions.

Based on the results of our study, we designed our storm protection plan and built on our previously approved storm hardening plans, including programs that apply extreme wind loading requirements to our overhead lines. The new programs included are overhead feeder hardening, overhead lateral hardening, overhead lateral undergrounding, transmission and substation resiliency, future system enhancements, and the storm protection plan management program.

We also propose to maintain and enhance certain programs such as the distribution pole and inspections and replacements, transmission system inspection and hardening, and the distribution and transmission vegetation management programs, which are largely covered through base rates. Most importantly, our proposed storm protection plan is designed with FPUC's unique service territory and customer base in mind.

Consistent with your rule, our storm protection plan includes a description of how each program will enhance FPUC's existing infrastructure, including how these programs will result in a reduction of outage times and restoration costs due to extreme weather conditions.

The plan also includes actual or estimated start and completion dates, cost estimates, and a comparison of cost and benefits, a description of the criteria used to select and prioritize the programs, and the annual jurisdictional revenue requirements.

The storm protection plan also includes more detailed information on the first three years of the plan on the estimated rate impact for customers and actual line circuit projects included.

Using these objectives and statutes as a baseline, we have taken a conservative approach by building on what has been accomplished to our storm hardening plan while including additional programs to protect our electric infrastructure, our customers and the communities in a cost-effective manner.

Thank you, Commissioners.

Q Thank you, Mr. Cutshaw.

MS. KEATING: Mr. Chairman, the witness is tendered for cross.

CHAIRMAN FAY: Great. Thank you.

Ms. Christensen, you are recognized.

MS. CHRISTENSEN: Thank you. Good afternoon, Commissioners.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good afternoon, Mr. Cutshaw.

A Good afternoon.

Q Mr. Cutshaw, you are the sponsor of FPU's plan?

A That's correct.

Q And you are not an attorney, is that correct?

A No, I am not.

Q But you are the person tasked with implementing the SPP rule for FPUC's systems, is that correct?

A That's correct.

Q Okay. And how many customers does FPUC have on both of its territory systems?

A It's approximately 30,000 customers.

Q Okay. Now, will you please turn to your direct testimony to the SPP plan, and specifically look at Section 3.0. And let me know when you get there.

A 3.0, Programs and Descriptions.

Q Correct. And you would agree that under each one of the program descriptions and benefits, there is a section called cost and benefits comparison, is that correct?

A That's correct.

Q Okay. And under that, you would say -- in reading your plan, I did not see that there were any dollar costs benefits outlined in any of those sections, am I correct?

A That's correct.

Q Okay. Now, I think you have a copy of the rule in front of you, but if you need to refer to it, would you agree that SPP rule section (3)(d) states that the utility is to provide a description of how each proposed storm protection program is designed to enhance the utility's transmission and distribution facilities, including an estimate of resulting reductions in outage times and restoration costs due to the extreme weather conditions?

A That is what is stated.

Q Okay. And would you also agree that the SPP rule requires that you provide an estimate of the resulting reduction -- reductions in those outage times and storm costs due to those extreme weather conditions?

A And we feel like we accomplished that, although, being a qualitative as opposed to a quantitative amount, we did describe those cost and benefits.

Q Okay. So just to confirm, you did not provide

a dollar estimate of the reduction of restoration costs, correct?

A We did not give dollar values, correct.

Q And you also did not provide an estimate of the reduction in outage times due to the extreme weather conditions, is that correct?

A That's correct.

Q Now, looking on page 39 of your SPP plan, if I can have you turn there.

A Okay, I am there.

Q Okay. That is the page where you have provided the estimated SPP bill impacts for the next three years, that's 2023 through 2025, is that correct?

A Correct.

Q Okay. And let me have you refer to -- well, and let me clarify one thing.

Those SPP impacts, do they include any existing storm hardening programs that are currently being recovered in base rates?

A These are impacts of those areas that are outside of the base rate impacts.

Q Okay. So let's look at page, I believe it is seven of your direct testimony. In looking at page seven of your direct testimony, you talk about the programs that are currently storm hardening programs, is

that correct? No, I am sorry, page five.

A Yes.

Q Okay. And the current programs, with slight modifications, that are currently in base rates, those would be distribution pole inspection and replacement, transmission system inspection and hardening, and vegetation management programs, correct?

A That's correct.

Q And just to make sure I am clear, the rates that we referred to on page 39 of the SPP does not include the majority of the costs associated with those programs?

A Correct.

Q Okay. And then as part of your SPP program, you are planning on adding additional programs for overhead feeder hardening, overhead lateral hardening, overhead lateral undergrounding, transmission and substation resiliency, and future system enhancements, correct?

A Correct.

Q And those are the costs that are currently included in that calculation on page 39, correct?

A Correct.

Q Okay. And let me have you turn your attention to page 44 of the SPP program. Okay. And let me know

when you get there.

A Okay. I am there.

Q Okay. And this is FPUC's 2022 through 2031 estimated storm protection plan costs by program in the millions, correct?

A Correct.

Q Okay. And if you look at, starting in 2024 and then through 2026. Are those the years that the transmission line projects that FPU is proposing are going to go into the SPP in the cost?

A That's correct.

Q Okay. And in 2025 and 2026, is -- are those the years the majority of the costs for the 38 k -- or is it 138 kV line costs are going to be put into service for FPUC?

A Yes. That is correct.

Q Let me just ask you this: The current transmission line from the mainland to Amelia Island, how long has that been in service?

A It has gone through a number of modifications. Back in 2001, it was upgraded, and then there were some modifications done again in the last, or since 2016. But prior to that, it's been in service probably from the early '70s.

Q Okay. And that current transmission line,

that's currently had the same route over the -- over to the island --

A Yes?

Q -- since the '70s?

A Yes.

MS. CHRISTENSEN: Okay. All right. I have no further questions. Thank you.

CHAIRMAN FAY: Great. Thank you.

Staff?

MR. IMIG: No questions.

CHAIRMAN FAY: All right. Commissioners?

Seeing none, Ms. Keating, you are recognized for redirected.

MS. KEATING: Thank you, Mr. Chairman, just a couple.

FURTHER EXAMINATION

BY MS. KEATING:

Q Mr. Cutshaw, Ms. Christian was asking you about the benefits, and how you demonstrated the benefits of your program. Will FPUC's storm protection plan reduce outage times?

A It will definitely reduce outage times and restoration costs by each and every one of the programs that we are putting in place or proposing.

I think it's general knowledge that a lot of the feeder hardening work that we are all proposing to do has been around since 2007, and it has made a huge impact on the systems that we have in place today.

Q And you have got some experience with restoration and restoration costs, correct?

A Yes.

Q In your experience, is it more costly to restore a system that has been damaged, or to preserve the system in the first instance?

A We -- I think we've proved that during Hurricane Michael, when something that wasn't supposed to happen happened, and then we were caught with a $70 million restoration event in something that shouldn't have happened but it did.

These programs will allow us to harden our system in a methodical, systematic method, rather than having to bring crews in from outside the service territory, feed them, house them, and have them replace poles in that situation.

Q And when you refer to something that shouldn't have happened but did, are you talking about the scope of the hurricane itself?

A Who would have thought that Hurricane Michael would have damaged Marianna like it did?

Q Ms. Christensen also asked you a few questions

about the project for the 138 kV line across Amelia River. Could you just tell us what happens if that line comes down?

A The line goes through some inaccessible locations. It crosses the intercoastal waterway. There are several things that could impact that, including an extreme weather event. And should those occur, the restoration could be days or weeks to get everything back up and repaired, and that is the only transmission service to Amelia Island.

MS. KEATING: Thank you, Mr. Chairman. No further questions --

CHAIRMAN FAY: Great.

MS. KEATING: -- on redirect.

CHAIRMAN FAY: Thank you.

Would you like to enter Mr. Cutshaw's exhibit?

MS. KEATING: Yes. FPUC would ask that Exhibit No. 12 be admitted into the record.

CHAIRMAN FAY: Without objection, show that entered.

(Whereupon, Exhibit No. 12 was received into evidence.)

CHAIRMAN FAY: All right. With that, Mr. Cutshaw, you are excused.

All right. I have 3:15. Next we will be

moving to OPC's Witness Mara.

MS. CHRISTENSEN: Yes, OPC would like to call Witness Mara to the stand.

Whereupon,

KEVIN J. MARA

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

CHAIRMAN FAY: You are recognized.

MS. MORSE: Okay. Thank you, Mr. Chair.

EXAMINATION

BY MS. MORSE:

Q Good afternoon, Mr. Mara.

A Good afternoon.

Q Will you please state your full name and business address for the record?

A My name is Kevin Mara. My business address is 1850 Parkway Place, Marietta, Georgia.

Q Were you previously sworn in?

A Yes, I was.

Q And did you cause to be filed prefiled direct testimony consisting of 36 pages, including a cover page and table of contents in Docket No. 20220051?

A Yes, I did.

Q Do you have any changes or corrections to your

testimony?

A I do not.

Q If I were to ask you the same questions today, would your answers be the same?

A They would.

MS. MORSE: Mr. Chairman, I would ask that the testimony of Mr. Mara be entered into the record as though read.

CHAIRMAN FAY: Show it inserted.

(Whereupon, prefiled direct testimony of Kevin J. Mara in Docket No. 20220051 was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.	DOCKET NO. 20220051-EI FILED: May 31, 2022

DIRECT TESTIMONY

OF

KEVIN J. MARA, P.E.

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

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DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20220051-EI

I. INTRODUCTION

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

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

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

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

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

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

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

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

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

- Vermont Department of Public Service
- Florida Public Service Commission

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

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

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. GDS Associates, Inc., was retained by the Florida Office of Public Counsel ("OPC") to review Florida Power & Light's ("FPL" or "Company") proposed 2023-2032 Storm Protection Plan ("SPP" or "Plan") on behalf of the OPC. Accordingly, I am appearing on behalf of the Citizens of the State of Florida.

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

A. I am presenting OPC's recommendations regarding FPL's proposed 2023-2032 Storm Protection Plan. My testimony serves to refute the testimony presented by Michael Jarro regarding the scope of the SPP projects and whether the programs and projects could qualify to be included in the SPP.

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

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

Q. PLEASE DESCRIBE HOW THE REMAINDER OF YOUR TESTIMONY IS ORGANIZED.

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

II. REVIEW THE PURPOSE OF STORM HARDENING

Q. PLEASE DISCUSS SECTION 366.96, FLORIDA STATUTES.

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

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

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

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

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

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

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

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

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

(1) Reduce restoration costs, and

(2) Reduce outage times.

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

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

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

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

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

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

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

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

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

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

A. Yes. Adding new sectionalizing equipment such as smart gird enhancements, SCADA systems and remotely operated air break switches (GOABs) do not reduce outages. The outage will still occur and will still need to be repaired. Thus, there is no change to the restoration costs. These devices only help to isolate a smaller portion of the system that is affected by the outage. Thus, the devices fail to meet the criteria in Rule 25-6.030, F.A.C. While the devices do reduce outage times, they fail to reduce outage costs. Further, adding sectionalizing equipment does not strengthen or harden the system.

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

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

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

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

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

A. Section 366.96, Florida Statutes, and Rule 25-6.030, F.A.C., provide no overt governance regarding limitations to the costs of SPP programs. It is imperative that the Commission consider guidelines to limit the magnitude of each program’s costs compared to its benefits.

For this reason, and on behalf of the customers who must bear these costs against the level of projected benefits, elsewhere in my testimony, I propose my limits to projects for the Commission to consider in the public interest.

Q. DID FPL PROVIDE ANY SPECIFIC COST REUDCTION FOR THE PROGRAMS PROPOSED IN THE 2023-2032 SPP?

A. No. FPL did not include any estimate of the cost reduction of the programs. Rule 25-6.030(3)(d)1, F.A.C., specifically requires utilities to file plans "including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions." The rule further requires a comparison of the costs of the programs and the benefits of the programs.[7] Without an estimate of the cost reduction for outages, it is impossible for any party to make a judgment on prudence. Mr. Jarro claims that a purpose of his testimony is to provide a comparison of benefits and costs for each program.[8] Mr. Jarro did not provide this critical information regarding the estimated cost reduction for the programs. Nor is this information contained in FPL's 2023-2032 SPP. Without this data, FPL's SPP fails to meet the requirements of Rule 25-6.030 F.A.C.

FPL's 2023-2032 SPP provides simplistically written descriptions of program benefits which are budgeted in the billions of dollars. This lack of attention to detail to justify the expenditures and to demonstrate the cost effectiveness of the programs undermines the purpose of the SPP.

In my opinion, anyone can claim reduction in outage restoration costs, but in a regulatory setting with the need to comply with specific statutes, it is necessary and

[7] Rule 25-6.030 (3)(d)3 and Rule 25-6.030 (3)(d)4, F.A.C.
[8] Direct testimony of Michael Jarro, p. 4, lines 13-14.

expected that monetized values of these reductions during extreme weather events be provided.

Q. DID FPL PROVIDE ANY SPECIFIC REDUCTIONS IN OUTAGE TIMES FOR THE PROGRAMS PROPOSED IN THE 2023-2032 SPP?

A. No. FPL did not include any estimate of the reduction of outage times. Even though Rule 25-6.030(3)(d)1, F.A.C. mandates “including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions.” I believe that the outage times should be monetized on a basis consistent with other utilities to help determine the benefits compared to the costs of the proposed storm hardening programs. FPL failed to provide an estimate, and instead provided only a statement of belief.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE LACK OF INFORMATION REGARDING THE REDUCTION IN OUTAGE COSTS AND REDUCTION IN OUTAGE TIME?

A. I recommend that FPL be required to amend their filing and provide the necessary data for each program as required by Rule 25-6.030 F.A.C., with an opportunity for intervenors to provide review and testimony.

Q. DID YOU COMPARE THE 10-YEAR CAPITAL COSTS OF FLORIDA POWER & LIGHT’S 2020-2029 SPP AND ITS 2023-2032 SPP?

A. Yes. I compared the combined budget for the 2020-2029 SPP filed by FPL and Gulf Power to the budget for FPL’s 2023-2032 SPP. The table below shows an increase of 34% or about $3.5 billion in capital spending over the 10-year plan compared to the previous Plan. This 34% increase in capital costs will put greater pressure on customers’ rates.

Capital	FPL and GP 2020-2029 SPP $million	Total 2023-2032 SPP $million	Difference	Percent Increase
Distribution Inspection Program	$ 593.80	$ 628.80	$ 35.00	6%
Transmission Inspection Program	$ 520.50	$ 657.20	$ 136.70	26%
Distribution Feeder Hardening Program	$ 3,499.30	$ 2,437.10	$ (1,062.20)	-30%
Distribution Lateral Hardening Program	$ 5,146.40	$ 9,388.50	$ 4,242.10	82%
Transmission Hardening Program	$ 600.80	$ 498.50	$ (102.30)	-17%
Distribution Vegetation Management Program	$ -	$ 28.40	$ 28.40	
Transmission Vegetation Management Program	$ -	$ -	$ -	
Substation Storm Surge/Flood Mitigation Progr	$ 23.00	$ 16.00	$ (7.00)	-30%
Distribution Winterization Program	$ -	$ 93.00	$ 93.00	New
Transmission Winterization Program	$ -	$ 44.60	$ 44.60	New
Transmission Access Enhancement Program	$ -	$ 115.80	$ 115.80	New
Total Capital	$ 10,383.80	$ 13,907.90	$ 3,524.10	34%

Q. HAVE YOU COMPARED THE CAPITAL COSTS ON A PER RATEPAYER BASIS FOR THE INVESTOR-OWNED UTILITIES THAT HAVE FILED SPP PLANS?

A. Yes. I looked at the ratio of capital spending to the number of customers for the 2020-2029 SPP and the 2023-2032 SPP for the electric utilities that filed plans. This information is in the following table:

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

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

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

While Tampa Electric and Duke had increases for the ten-year total just under 9%, FPL is showing an increase of 34%. The increase in spending by FPL of 34% is significant and will impact rate payers if left unchecked.

III. SUMMARY OF PROPOSED SPP REDUCTIONS

Q. CAN YOU SUMMARIZE YOUR PROPOSED REDUCTIONS IN FPL'S PROGRAMS?

A. The table below summarizes my recommendations to reduce FPL's 10-year SPP capital budget by $3.6 billion. These recommendations are detailed in my testimony.

Capital	Total 2023-2032 SPP $Millions	Reductions Proposed by Mara	Net 2023-2032 SPP $Millions	Reason for Reduction
Distribution Inspection Program	$ 629	$ -	$ 629	
Transmission Inspection Program	$ 657	$ -	$ 657	
Distribution Feeder Hardening Program	$ 2,437	$ -	$ 2,437	
Distribution Lateral Hardening Program	$ 9,389	$ (3,389)	$ 6,000	Limit impact to customers
Transmission Hardening Program	$ 499	$ -	$ 499	
Distribution Vegetation Management Program	$ 28	$ -	$ 28	
Transmission Vegetation Management Program	$ -	$ -	$ -	
Substation Storm Surge/Flood Mitigation Program	$ 16	$ (16)	$ -	Does not comply with 25-6.030
Distribution Winterization Program	$ 93	$ (93)	$ -	Does not comply with 25-6.030
Transmission Winterization Program	$ 45	$ (45)	$ -	Does not comply with 25-6.030
Transmission Access Enhancement Program	$ 116	$ (116)	$ -	Does not comply with 25-6.030
Total Capital	$ 13,907.9	$ (3,658.4)	$ 10,249.5	

The reductions I am proposing will result in reducing the capital cost per customer to $1,798, which is similar to the cost per customer for the combined FPL and Gulf Power 2020-2029 SPPs.

Q. IF LIMITS ARE PLACED ON THESE PROGRAMS SUCH AS LIMITING THE MAGNITUDE OF DEPLOYMENTS AND SHIFTING AGING INFRASTRUCTURE REPLACEMENT PROGRAMS TO STANDARD RATE BASE TREATMENT, DOES THAT REDUCE BENEFITS OF THE SPP?

A. Yes, it does. However, the reduction in benefits must be balanced against the impact to the ratepayers. In fact, the United States is experiencing its worst inflation in 40 years and consumers have seen steep increases in the price of gas and groceries, as well as escalating electric bills, specifically in Florida. Unless the Commission acts to limit the expenditures, the unchecked spending on SPP programs will result in an excessive burden on the rate payers.

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

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

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

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

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

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

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

FPL did provide an estimate for a range of avoided restoration expenses for the entire SPP 10-year period, which is from $406 million to a high of $3.082 million.[9] Over a 5-year period (2016 to 2020), FPL's restoration costs are $2.13 billion less $240 million spent in

[9] *See* Exhibit MJ-1, Appendix A Attachment 1.

preparation for Dorian which did not make landfall and where FPL did not incur significant damage. FPL's costs for extreme storm restoration from 2016 to 2020 are $1.89 billion. Comparing this 5-year total restoration cost to the 10-year SPP budget of $13.9 billion shows that the costs far exceeded the *possible* benefits. Further, the cost exceeds FPL's range of avoided costs. In fact, FPL's capital SPP investment for the 10-year period is $13.9 billion which is more than 3.4 times the total cost of all storms affecting all investor-owned utilities in Florida. Thus, ratepayers are paying more for the SPP and reduced storm costs compared to the electric utilities doing no storm hardening.

IV. REVIEW OF SPP PROJECTS

Q. CAN YOU DESCRIBE THE SUBSTATION STORM SURGE/FLOOD MITIGATION PROGRAM?

A. Yes. This program is designed to prevent/mitigate substation equipment damage and customer outages due to storm surge and flooding.[10] The program provides for raising the equipment at certain substations above the flood level and constructing flood protection walls around other substations.[11]

Q. WHAT IS YOUR UNDERSTANDING OF BUILDING A SUBSTATION IN COASTAL FLOOD ZONES?

A. The acquisition of land for a substation is always a challenge but the land needs to be suitable for safe and reliable electric service. The flood maps were not issued until 1973[12] so a substation constructed before 1973 would not have had standards requiring certain

[10] *See* Exhibit MJ-1, p. 51 of 63.
[11] *See* Exhibit MJ-1, p. 51 of 63.
[12] *See* Exhibit KJM-2, *A Chronology of Events Affecting the National Flood Insurance Program,* FEMA, pp. 14-15.

elevations. For example, the St. Augustine Substation was originally built in 1927 and rebuilt in 1969.[13] However, stations built after 1973 should have been designed with the knowledge of potential flood waters, and designs should have accounted for this predictable occurrence. Specifically, the *Standard ASCE-24-14 Flood Resistant Design and Construction* recommends the facilities to be designed for the Basic Flood Elevation (100-year flood level) plus two feet. Details of improvements are not required to be contained in the current SPP; thus no conclusion can be reached regarding prudence of the original design and the proposed mitigation plans.

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

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

[13] Docket No.20200071-E1, FPL's Response to OPC's Fourth Set of Interrogatories, Interrogatory No. 214.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SUBSTATION STORM SURGE/FLOOD MITIGATION PROGRAM?

A. I recommend inclusion of this program on a limited basis. The program should exclude any substation where there are alternate feeds to allow the substation to be de-energized due to flooding. The program should also exclude any substation that has not had a history of flooding or for which a flooding threat cannot be demonstrated. The exclusions from the program are substations that do not meet the requirements of Rule 25-6.030, F.A.C. for a known benefit of the project.

Q. CAN YOU DESCRIBE FPL'S WINTERIZATION PROGRAM THAT IS INCLUDED IN FPL'S 2023-2032 SPP?

A. Yes. FPL included two new programs in the 2023 SPP related to winterization: one for distribution winterization and another for transmission winterization. According to FPL, the new projects contained in FPL's 2023 SPP will focus on increasing capacity to certain T&D facilities to better meet the forecasted increase in demand associated with an extreme cold weather event.[14] Mr. Jarro claims that the intent is to mitigate restoration costs and outage times associated with extreme cold weather events similar to what occurred in Texas.[15] For the Distribution Winterization Program, FPL proposes a ten-year budget of $93 Million[16] and for the Transmission Winterization Program, FPL proposes a ten-year budget of $44.6 million.[17]

[14] Direct Testimony of Michael Jarro, p. 10, lines 11-13.
[15] Direct Testimony of Michael Jarro, p. 10, lines 18-20.
[16] *See* Exhibit MJ-1, Appendix C.
[17] *See* Exhibit MJ-1, Appendix C.

Q. IN YOUR OPINION DOES THE ENABLING LEGISLATION ALLOW FOR WINTERIZATION PROGRAMS?

A. No. Per Rule 25-6.030, the purpose of the SPP is to "strengthen the 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, and vegetation management."[18] Extreme weather conditions are not defined within the Rule; however, all of the mitigation programs described in the rule focus on hardening the systems for hurricanes and tropical storms with high winds. Section 366.96, Fla. Stat. provides guidance on the definition of extreme weather conditions in that the enabling legislation begins with the statement "[d]uring extreme weather conditions, high winds can cause vegetation and debris to blow into and damage electric transmission and distribution facilities, resulting in power outages."[19] Further 366.96(1)(b), Fla. Stat. also states that "a majority of power outages that occur during extreme weather conditions in the state are caused by vegetation blown by wind." Thus, it is clear that the extreme weather conditions contemplated by the statute are wind-driven events that directly impact the facilities themselves. There are no references to winter or hot summer events in the statute nor are there any references to very low temperatures or very high temperatures which could cause high load conditions.

[18] Rule 25-6.030 (3)(a), F.A.C.
[19] Section 366.96 (1)(a), Florida Statutes.

Q. CAN YOU DESCRIBE HOW PLANNING CRITERIA ARE USED IN THE DESIGN OF TRANSMISSION AND DISTRIBUTION SYSTEMS AS THEY RELATE TO THIS WINTERIZATION PROGRAM?

A. Yes. Normally, electric utilities develop load projections for planning studies often based on a 90/10 methodology which uses the highest peak in the last ten year period to help ensure that the load projection will meet the hottest summer (or winter) peak in a ten-year period. Often there are projections based on past system and regional peaks, which in Florida, are more often summer peaks. Some utilities also consider winter peaks depending on the loading of the system. These load projections, coupled with operational planning criteria, are used to determine when system components need to be upgraded. In this case, it appears that FPL is proposing to change its planning criteria to now include a winter event that FPL speculates will occur once every 35 years.[20] This change in planning criteria has resulted in projected overloads of system components that FPL apparently did not previously consider. This change in loading criteria results in what amounts to a request to spend $137.6 million in capital to increase capacity of electrical components for what appears to be an indeterminately low probability event. It is my understanding that FPL made no attempt to estimate the probability of an extreme cold event in the future.

Q. SHOULD INCREASED CAPACITY TO SERVE LOW PROBABILITY, LOW TEMPERTURE EVENTS BE INCLUDED IN THE SPP?

A. No. When there are increases in load on an electric utility system, the utility will increase capacity as needed to adequately serve customers. Increasing electrical capacity is not, in my view as an engineer, permitted by the controlling statute, as previously discussed. If

[20] See Exhibit KJM-5, FPL's Response to OPC's Fifth Request for Production of Documents, Production of Document No. 33, p. 10 of 28.

these base rate-type capacity upgrades resulting from a change in planning criteria for abnormal winter temperatures can be funded through the SPP, then logically, one would expect that nearly all new substations, existing substation capacity increases, transmission line upgrades, many distribution feeder upgrades, and upgrades to distribution transformers will all be funded through the SPP and SPPCRC rather than through a standard rate case, as would be required in the normal course of business. This is clearly not what the SPP process was intended to permit. In my opinion, FPL's budgets for the winterization programs will increase as loads grow in the future. Capacity increases are necessitated due to increased load which in turn leads to increased revenue to help offset the investment of the capital. Review of these investments compared to the load increases should be subject to a prudence review by stakeholders. Embedding these upgrades in an SPP cost recovery process eliminates the vital role of base rate prudence reviews for capacity increases.

Q. DID FPL DEMONSTRATE THAT RESTORATION COSTS ARE REDUCED AND THAT OUTAGE TIMES ARE REDUCED AS A RESULT OF THE DISTRIBUTION WINTERIZATION PROGRAM?

A. No. Rule 25-6.030(3)(a), F.A.C. and Rule 25-6.030(3)(d)(1), F.A.C. require utilities to describe how implementation of a proposed SPP program will reduce restoration costs and outage times, and to compare program costs to the benefits of the program. However, not only did FPL fail to show that there have been any historical outages due to winter events from electrical overloads on field transformers, voltage regulators, or substation transformers, but FPL also failed to show there have been any costs associated with the restoration of the alleged outages caused by overloaded field transformers, voltage regulators or transformers in its territory caused by winter events. Instead, FPL alleged that the historical "extreme" cold weather events limited availability of Florida purchases or imports of electricity to meet increased demand and resulted in customer outages.[21] For the Distribution Winterization Program, FPL did not include any evidence regarding outages to customers from abnormally low winter temperatures. Nor did FPL provide evidence of failures of substation transformers, voltage regulators, phase reactors or field transformers.

In terms of mitigation, FPL only claimed that the Distribution Winterization Program will help mitigate restoration costs and outage times associated with what it characterizes as extreme cold weather events[22] without providing any evidence for this statement. Absent any evidence of outages, it is not possible to ascertain an improvement of the system performance during an abnormally low winter temperature. Specifically, the rule requires a reduction in restoration costs, and FPL has not provided any evidence of any restoration at all, hence there can be no reduction. Thus, there is no evidence that increasing the capacity of these distribution assets will reduce outage times or restoration costs.

Q. ARE YOU AWARE OF ANY EVIDENCE OF DISTRIBUTION SYSTEM OUTAGES ON FPL'S SYSTEM DUE "EXTREME" WINTER EVENTS?

A. Yes. In response to data requests by OPC, FPL provided a PowerPoint presentation entitled January 2010 Winter Analysis.[23] The analysis discussed outages occurring in and around a low temperature winter event from 12 years ago that occurred on January 10, 2010. For Gulf Power's service area, the outages primarily only required re-fusing to restore power rather than repair or replacement of system components. For overhead equipment, 69% of the outage causes did not result in the need to replace the transformer. The causes were

[21] *See* Exhibit MJ-1 p. 53 of 63.
[22] *See* Exhibit MJ-1, p. 54 of 63.
[23] *See* Exhibit KJM-3, FPL's Response to OPC's First Request for Production of Documents, Production of Document No. 1.

bad jumpers, bad connectors, fuse switches, etc. Normally, short-term overloading of a transformer does not require replacement of the unit.

FPL's analysis also noted that Gulf Power's outages were simply a result of a limitation of the feeder to carry the load and that no repair or restoration was needed, such as replacing poles during the event. FPL had 43 outages listed as equipment failure and these appear to be mostly related to bad jumpers and connectors.[24]

Q. WHAT IS FPL'S PROPOSED CRITERIA FOR REPLACING TRANSFORMERS DUE TO "EXTREME" WINTER EVENTS?

A. Based solely on FPL's response to OPC's request for production of documents,[25] it appears that FPL suggests using a multiplier of 1.35 on the projected summer peak to predict the winter peak. This proposed change in philosophy about sizing transformers results in a significant cost increase to rate payers. The method proposed by FPL is too simplistic for prudent engineering practice. An engineer should be aware of the types of loads (type of heating) at a particular transformer prior to using an across-the-board 1.35 multiplier on a projected summer load to make determinations about equipment replacement and upgrade. A transformer should be considered for replacement only after clearly researching and demonstrating the potential for a probable winter.

[24] *See* Exhibit KJM-3, FPL's Response to OPC's First Request for Production of Documents, Production of Document No. 1, (page 21 of the 2010 winter event or Bates FPL 000140).
[25] *See* Exhibit KJM-3, FPL's Response to OPC's First Request for Production of Documents, Production of Document No. 1 (page 15 of the 2010 winter event or Bates FPL 000133).

Q. DID FPL DEMONSTRATE BENEFITS FOR THE TRANSMISSION WINTERIZATION PROGRAM?

A. No. Rule 25-6.030(3)(a), F.A.C. and Rule 25-6.030(3)(d)(1), F.A.C. require utilities to describe how implementation of a proposed SPP program will reduce restoration costs and reduce outage times, and to compare program costs to the benefits of the program. As with the Distribution Winterization Program, FPL only noted limitations on imports of power during cold weather events and suggested those limitations caused outages.[26] FPL did not indicate any specific transmission outages caused by historical "extreme" cold weather events which will be solved by upgrading certain transmission lines.

Q. ARE YOU AWARE OF ANY EVIDENCE OF TRANSMISSION SYSTEM OUTAGES ON FPL'S SYSTEM DUE TO "EXTREME" WINTER EVENTS?

A. Yes. In response to data requests by OPC, FPL provided a PowerPoint presentation entitled January 2010 Winter Analysis.[27] The analysis discussed outages occurring in and around a low temperature winter event from 12 years ago that occurred on January 10, 2010.

There were only a few transmission outages during the event in January 2010 which resulted in 1.97 million customer minutes interrupted (CMI).[28] Approximately 70% of the CMI were caused by failure of substation equipment and the remaining 30% of the CMI was attributed to a deteriorated transmission line and thermal loading on two transmission lines resulting in service interruption of less than 100 minutes.[29] For system benefits, FPL claims the Transmission Winterization Program will enable FPL to better serve forecasted

[26] *See* Exhibit MJ-1, p. 53 of 63.
[27] *See* Exhibit KJM-3, FPL's Response to OPC's First Request for Production of Documents, Production of Document No. 1.
[28] *See* Exhibit KJM-3, FPL's Response to OPC's First Request for Production of Documents, Production of Document No. 1 (page 18 of the 2010 winter event or Bates FPL 000137).
[29] *See* Exhibit KJM-3, FPL's Response to OPC's First Request for Production of Documents, Production of Document No. 1 (page 18 of the 2010 winter event or Bates FPL 000137).

loads during postulated "extreme" cold weather that could become overloaded and fail. The proposed transmission capacity increases will not correct 70% of the CMI that occurred in 2010 and the total time for the winter related to transmission line outages for thermal loading was limited 110 minutes. It is important to note that in the 2010 event, no transmission conductor was replaced, and no transmission structures had to be repaired or replaced to restore electric service.

If a component is approaching its capacity limit, a properly designed system will isolate the component prior to failure. This type of isolation is totally different from extreme wind events which result in catastrophic failures of structures and conductors. With a system isolation, the restoration cost is minimal because the system component does not fail. Outage times during an isolation can occur, but simply reducing these outage times which have not been estimated nor considered does not justify this program as required by Rule 25-6.030, F.A.C.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE DISTRIBUTION AND TRANSMISSION WINTERIZATION PROGRAMS PROPOSED BY FPL?

A. I recommend that these newly proposed Distribution and Transmission Winterization programs be excluded from FPL's Storm Protection Plan. These programs were budgeted for $93 million and $44.6 million in capital respectively.

Q. CAN YOU DESCRIBE FPL'S TRANSMISSION ACCESS ENHANCEMENT PROGRAM THAT IS INCLUDED IN FPL'S 2023-2032 SPP?

A. Yes. This is a newly proposed program which is supposed to permit access to transmission facilities for restoration activities following an extreme weather event.[30] The projected capital budget for this program is $115.8 million.[31]

Q. HOW DOES FPL USE ITS TRANSMISSION RIGHT OF WAY?

A. Electric utilities such as FPL use transmission right-of-way to maintain a clear distance from vegetation and to maintain clearances to transmission conductors. In order to maintain structures, maintain the right of way (cutting brush and trees), and to inspect lines, utilities will have a means such as a road or access drive to accomplish these tasks. The maintenance of these roads and access points is a core function of an electric utility that owns transmission lines. When the line was originally constructed, large vehicles needed access to install poles and the access roads were established. The utility normally maintains this access into the future. For example, FPL has reported that 99% of the transmission structures in the former FPL service area are now steel or concrete due to the transmission hardening program.[32] To replace wood transmission poles with the newer steel or concrete poles, FPL needed access to the poles. It is not clear why FPL did not previously see the need to prudently maintain its access roads in the ordinary course of business to allow for replacement and maintenance of transmission structures in the future.

[30] *See* Exhibit MJ-1, p. 57 of 63.
[31] *See* Exhibit MJ-1, Appendix C.
[32] *See* Exhibit MJ-1, p. 39 of 63.

Q. DID FPL DESCRIBE ALTERNATIVES TO THE NEWLY PROPOSED TRANSMISSION ACCESS ENHANCEMENT PROGRAM?

A. Yes. FPL mentions the use of specialized equipment to access difficult terrain including track vehicles, large tire vehicles and floating equipment.[33] It is true that these vehicles often have limited availability during storm events.[34] However, purchasing and maintaining these vehicles may be more cost effective than expending $115.8 million in capital cost for maintenance of roads and bridges. Another concern is that the roads may not be passable for normal trucks due to high water but could be passable with specialized vehicles. In my opinion, this alternative needs to be fully explored and evaluated to determine the most prudent course of action before including the $115.8 million in the SPP.

Q. DID FPL DEMONSTRATE REDUCTION IN OUTAGE RESTORATION COSTS AND OR REDUCTION IN OUTAGE TIMES FOR THE TRANSMISSION ACCESS ENHANCEMENT PROGRAM?

A. No. In Section IV(K)(4), FPL listed the benefits associated with the Transmission Access Enhancement Program discussed in Section II(A) and Section IV(K)(1)(b). Section II(A) only discusses the existing SPP programs and does not address this new program.[35] Section IV(K)(1)(b) does not exist in the FPL filing. Section IV(K)(1) discusses benefits in vague terms with no defined outage time reduction or restoration cost reduction. Adding a culvert or bridge can increase access but if the right of way is flooded, it does not matter if there is a bridge or culvert and the investment of $115.8 million will have not resulted in enhanced access. Regarding the benefits of this new program, the storm analysis included

[33] *See* Exhibit MJ-1, p. 58 of 63.
[34] *See* Exhibit MJ-1, p. 58 of 63.
[35] *See* Exhibit MJ-1, p. 8 of 63.

as Appendix A to Exhibit MJ-1 is not applicable since the program did not exist at the time of that analysis.

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

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

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

Another consideration, similar to the rationale underlying the winterization proposal, is that if this program truly adds benefits of better access, then a similar program could be justified for building roads, bridges, and culverts to any hard to access distribution line. Obviously, distribution lines impact fewer customers, but if the only justification needed is claiming reduction of restoration time, then the program could easily be expanded to distribution lines. As guardians of the SPP, the Commission should resist creating this slippery slope as a means of minimizing customer rate impacts caused by "mission creep."

For these reasons, it is my opinion, that FPL fails to meet the requirements of Rule 25-6.030(3)(d)(4), F.A.C.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TRANSMISSION ACCESS ENHANCEMENT PROGRAM PROPOSED BY FPL?

A. I recommend that the newly proposed Transmission Access Enhancement program with a capital budget of $115.8 million be excluded from the Storm Protection Plan.

Q. CAN YOU DESCRIBE THE DISTRIBUTION LATERAL HARDENING PROGRAM?

A. Yes. This program was introduced as part of FPL's 2018 Storm Hardening Plan as the Storm Security Underground Plan (SSUP) pilot that was identified as a program targeting certain overhead laterals that were impacted by recent storms, and which have a history of vegetation-related outages and other reliability issues, for conversion from overhead to underground.[36] In the Settlement of the 2022 SPP, this plan was renamed Distribution Lateral Hardening pilot program.[37] The pilot was to extend to the end of 2022.[38] Thus, the Distribution Lateral Hardening Program is actually a new program to the current SPP. This program now has two options for existing overhead laterals; harden the overhead lateral[39] or underground the lateral. The hardening option is not well-defined in FPL's

[36] *See* Exhibit MJ-1, p. 29 of 63.
[37] *See* Exhibit KJM-4, Order No. PSC-2020-0293-AS-EI, issued August 28, 2020, in Docket No. 20200092-E1, p. 5 (a.k.a. 2020 Settlement Order for SPP).
[38] *See* Exhibit MJ-1, p. 29 of 63.
[39] *See* Exhibit MJ-1, p. 28 of 63.

filing but appears similar to the performance standards for hardening an overhead feeder. The scope for undergrounding laterals is similar to the scope for undergrounding used for the pilot program.

Q. CAN YOU DESCRIBE WHAT IS MEANT BY THE TERM LATERAL?

A. Yes. The term lateral is critical to understanding the purpose of the Distribution Lateral Hardening program. A distribution circuit can be described as a combination of the mainline feeder with laterals stemming from the main line. The Distribution Feeder Hardening program increases the strength of the feeder from the substation to some point further along the circuit, such as a three-phase tie point with another circuit. Some describe the mainline feeder as the first zone of protection out of the substation, meaning the breaker in the substation protecting the entire circuit will trip for any fault in this zone of protection. Thus, by hardening the first zone of protection, it greatly reduces the chance of a structure failure during an extreme wind event which could cause an extended outage for all customers served by the circuit. Simply, laterals are taps off the main line and FPL has 27,000 miles of laterals on its system compared to approximately 14,000 miles of mainline feeders.[40] These laterals can be single-phase taps into residential neighborhoods or three-phase taps to subdivisions or businesses. Many of the laterals are behind customers' premises. The design goal is this: by hardening/strengthening the mainline feeder and undergrounding the laterals, the circuit will have fewer outages from a major wind event.

[40] *See* Exhibit MJ-1, p. 27 of 63.

Q. WHAT IS THE MAGNITUDE OF THE DISTRIBUTION LATERAL HARDENING PROGRAM?

A. The total 10-year capital budget is $9.39 billion.[41] This is an increase of 26% from the 2020 SPP which includes Gulf Power and FPL. The $9.39 billion capital expenditure is approximately 67% of FPL's total SPP budget for 2023-2032.

Q. WHAT BENEFIT IN TERMS OF REDUCTION IN OUTAGE RESTORATION COST AND REDUCTION IN OUTAGE TIME MAY RESULT FROM UNDERGROUNDING THESE LATERALS?

A. The benefit value is unknown. FPL did not meet the requirements of Rule 25-6.030, F.A.C. because the 2023-2032 SPP does not contain any estimate of the cost reduction to be realized from the Distribution Lateral Hardening program. This program, which is 67% of the total SPP budget, should have a magnitude in reduction in costs commensurate to the total budget.

FPL provides their estimate of the 40-year net present value to reducing storm recovery costs for the entire hardening program, and this value depends on the assumed frequency of storms (every 3 years or 5 years) and the type of storm (Hurricane Michael and Hurricane Irma). The range of FPL's analysis shows a low of $406 million and a high of $3,082 million.[42]

Even at the highest range and including all hardening projects, the benefit to cost ratio ranges from 3% to 20% of the total hardening budget. In my opinion this suggests the benefit to cost ratio for undergrounding laterals will also range from 3% to 20%.

This ratio indicates that for every $5 spent only $1 in benefit is gained.

[41] *See* Exhibit MJ-1, Appendix C, p. 2.
[42] *See* Exhibit MJ-1, Appendix A Attachment 1.

Q. WHAT IS THE PRIORITY OF THE DISTRIBUTION LATERAL HARDENING PROGRAM?

A. FPL will prioritize based on an overall feeder performance methodology.[43] That is, FPL will identify the worst performing feeders and initially focus on these feeders. Starting in 2025, FPL proposes an additional selection methodology that targets hurricane-prone areas, highest concentration of customers, and areas that would require significant transit for out of state crews.[44] Once a feeder is identified, FPL will determine which laterals on the feeder will be undergrounded or hardened.[45]

Q. DO YOU AGREE WITH THE METHODOLOGY PROPOSED BY FPL FOR THE UNDERGROUNDING OF LATERALS?

A. No. Undergrounding power lines/laterals is an expensive proposition and one that should not be undertaken lightly. On average there 20-30 laterals on a feeder. The average cost to underground a lateral ranges from $653,875 to $871,833.[46] Thus, if a feeder will have all laterals undergrounded, the cost per feeder ranges from $13.0 million to $26.1 million.[47] The average feeder on FPL's system serves 1,593 customers,[48] which means the investment per customer ranges from $8,158 to $16,379. My point is that the dollars are concentrated such that only a few customers will see a reduction in customer outage minutes and enjoy the aesthetics and other benefits of an undergrounded system. The remaining customers only see a benefit cost ratio that is upside down meaning more costs than benefits.

[43] *See* Exhibit MJ-1, p. 36 of 63.
[44] *See* Exhibit MJ-1, p. 36 of 63.
[45] See Exhibit MJ-1, p. 35 of 63.
[46] *See* Exhibit MJ-1, Appendix C, p. 2.
[47] 20 times $653,875 for the low range and 30 times $871,833 for the high range.
[48] *See* Exhibit MJ-1, Appendix E (which was updated in early May).

This is a significant investment in a small portion of the system (one feeder) and in a single community. There needs to be a mechanism to help spread the undergrounding and hardening to more communities, which is important since all customers will be contributing to the cost of undergrounding.

Q. DO YOU HAVE A RECOMMENDATION FOR TRACKING COSTS ASSOCIATED WITH THE DISTRIBUTION LATERAL HARDENING PROGRAM?

A. Yes. This program should be separated into two projects. One for hardening overhead laterals and one for undergrounding laterals. There is a significant cost difference between hardening an overhead lateral and undergrounding a lateral. Tracking costs and reviewing the prudence of projects would be easier if these two distinct solutions are tracked separately.

Q. DO YOU HAVE A RECOMMENDATION FOR THE DISTRIBUTION LATERAL HARDENING PROGRAM?

A. Yes. I recommend reducing the budget for the Distribution Lateral Hardening program. I recommend a capital budget of roughly $6.0 billion. Essentially, my recommendation uses the same budgets proposed by FPL for the first 2 years (2023 to 2024) and then caps the annual spending for this program to roughly $606 million per year for the years 2025 to 2032. This recommended budget is shown in the following table.

Overhead Lateral Hardening

Year	FPL 2023 SPP $millions	Recommended 2023 SPP $millions
2023	$ 523	$ 523
2024	$ 628	$ 629
2025	$ 758	$ 606
2026	$ 889	$ 606
2027	$ 1,019	$ 606
2028	$ 1,049	$ 606
2029	$ 1,081	$ 606
2030	$ 1,113	$ 606
2031	$ 1,147	$ 606
2032	$ 1,181	$ 606
Total	**$ 9,389**	**$ 6,000**

The basis for the reduction is two-fold. First, FPL has failed to demonstrate any cost reduction from outages due to this program of undergrounding laterals or hardening existing laterals. It is apparent from experiences in Florida that undergrounding and hardening poles will reduce outage costs and outage times, but the extent to which this will be true for the Overhead Lateral Hardening program is unknown, and therefore should be scaled back. Second, FPL's overall 2023 SPP has a high cost per customer and will result in higher rates for customers. Capping the spending is also necessary to relieve some of the rate impacts on customers and ensure the costs are reasonable, as required by the SPP statute.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

BY MS. MORSE:

Q Mr. Mara, did your prefiled testimony have five exhibits attached labeled KJM-1 through KJM-5?

A Yes, it did.

MS. MORSE: And, Mr. Chair, I will note that those KJM-1 through 4 have already been identified in the CEL as numbers 16 through 19.

BY MS. MORSE:

Q Mr. Mara, do you have any corrections to your exhibits?

A No, I do not.

Q Would you please summarize are testimony? I am sorry. I apologize, Mr. Mara.

MS. MORSE: We have more introductions to come, Mr. Chair.

MS. HELTON: Mr. Chairman, I just want to make sure we got Ms. Morse's information correct, because I am showing that Mr. Mara has five exhibits, and I think she only identified four, so --

MR. REHWINKEL: I think one was withdrawn, or one was not on the CEL because it related to the winterization.

MS. HELTON: Oh, okay. Thank you. Thank you. So KJM-5 is no longer good. I think she said exhibit, or maybe I heard it prong, but I thought she said Exhibit 59, did we really mean 49 if that was the case?

MR. REHWINKEL: Yeah, exhibits 16 through 19 --

MS. HELTON: Okay.

MR. REHWINKEL: -- are the ones that we are identifying.

MS. HELTON: Okay. I apologize. That didn't match up to what I had, but I am good now. Thank you.

CHAIRMAN FAY: That's KJM-1 through 4, and those are marked has 16 through 19, correct?

MR. REHWINKEL: Yes. And just, Mr. Chairman, at the -- at the -- after Ms. Christensen introduces his testimony in the FPUC docket, we will do the summary all at one time.

CHAIRMAN FAY: Okay.

EXAMINATION

BY MR. REHWINKEL:

Q Hello again.

A Hello.

Q In the Duke Energy Florida proceeding, 20220050, did you prepare -- I guess we will just keep the record clean.

Can you state your full name?
A Kevin Mara.
Q Thank you. Can you state your business address for the record?
A 1850 Parkway Place, Marietta, Georgia.
Q And whose behalf are you testifying in this docket?
A The Office of Public Counsel.
Q And I think you were sworn previously?
A I was.
Q Did you cause to be filed amended direct testimony on June 27th, 2022, consisting of 42 pages?
A Yes, I did.
Q Do you have any changes or corrections to make to that testimony?
A I don't have any changes to the amended testimony, no.
Q Thank you.
And with -- if I asked you today the questions included in your prefiled, amended prefiled testimony, would your answers be the same?
A They would indeed.
MR. REHWINKEL: Mr. Chairman, I would ask that Mr. Mara's amended direct testimony, and only the clean version, be entered into the record.

CHAIRMAN FAY: Okay.

(Whereupon, prefiled direct testimony of Kevin J. Mara in Docket No. 20220050 was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.	DOCKET NO. 20220050-EI FILED: May 31, 2022

AMENDED DIRECT TESTIMONY

AND EXHIBITS

OF

KEVIN J. MARA, P.E.

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

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EXHIBITS

AMENDED DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20220050-EI

I. INTRODUCTION

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

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

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

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

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

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

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

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

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

- Vermont Department of Public Service

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

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

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. GDS Associates, Inc., was retained by the Florida Office of Public Counsel ("OPC") to review Duke Energy Florida's ("Duke," "DEF," or "Company") proposed 2023-2032 Storm Protection Plan ("SPP" or "Plan") on behalf of the OPC. Accordingly, I am appearing on behalf of the Citizens of the State of Florida.

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

A. I am presenting my recommendations on behalf of OPC regarding DUKE's proposed 2023-2032 Storm Protection Plan. My testimony serves to refute the testimony presented by Brian M. Lloyd and Amy H. Home regarding the scope of the SPP projects, and whether the programs and projects could qualify to be included in the SPP, absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, as discussed in certain circumstances below.

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

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

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I first discuss the purpose of storm hardening and an SPP as informed by Rule 25-6.030, F.A.C., and criteria needed for storm hardening projects. I then discuss principles to be applied when reviewing DEF's proposed SPP. I also address the level of spending by DEF. Finally, I discuss my analysis of the new programs proposed in the SPP, including principles that should be applied when reviewing DEF's proposed SPP. In the discussion of the principles I applied, I include criteria that, in my expert opinion, the Commission must weigh to properly evaluate the sufficiency of the SPP and each SPP program under the statutes and rules governing the SPPs, subject to a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, as discussed in certain circumstances below. To the extent that the portions of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

II. REVIEW THE PURPOSE OF STORM HARDENING

Q. PLEASE DISCUSS SECTION 366.96, FLORIDA STATUTES.

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

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

All of the utilities' SPPs are based on the premise that by investing in storm hardening activities the electric utility infrastructure will be more resilient to the effects of extreme weather events. This resiliency means lower costs for restoration from the storms

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

and reduced outage times experienced by the customers. Some programs have a greater impact on reducing outages times and lowering restoration costs than other programs. Clearly, the goal is to invest in storm hardening activities that benefit the customers of the electric utilities at a cost that is reasonable relative to those benefits.

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

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

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

Logically, strengthening the electric utility infrastructure is a storm plan requirement and simply replacing like-for-like equipment with the same strength and functionality does not meet the requirements of Rule 25-6.030, F.A.C. The point of the SPP is to enhance the strength of the grid to withstand extreme weather conditions that result in high winds.

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

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

(1) Reduce restoration costs, and

(2) Reduce outage times.

Rule 25-6.030, F.A.C., requires utilities to provide budgets for programs and to provide the estimated reduction in restoration costs.[5] These amounts must be balanced against the benefits to the utilities' customers. Further, the two amounts will allow the Commission and stakeholders to understand the benefits of the capital investments for storm hardening relative to the "reasonableness" of the costs. Any program can claim to reduce outage costs and outage time; however, the program must be cost effective for customers to benefit. To summarize, the rules require a two-prong test for consideration of a program: reduction in outage costs and reduction in outage time.

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

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

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

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

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

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

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

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

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

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

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

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

In DEF's current 2023 SPP filing there are several programs such as replacement of deteriorated conductors, replacement of antiquated relays and breakers, replacement of rusted switchgear, replacement of live-front transformers, corrosion mitigation to increase service life, and replacement of lattice towers with lattice towers of similar strength, that are **not** storm hardening programs. These are aging infrastructure programs which do not decrease outage costs or reduce outage time when compared to existing system infrastructure. DEF should be implementing the renewals of aging infrastructure through standard base rates primarily because these programs are not related to protecting the system in Florida from damage from storms but could be more accurately classified as ordinary replacements. I would recommend not including these programs in the updated SPP absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI

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

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

Q. DID YOU COMPARE THE 10-YEAR CAPTIAL COSTS OF DEF'S 2020-2029 SPP AND ITS 2023-2031 SPP?

A. Yes, there has been a substantial increase in capital expenditures proposed by DEF. The table below shows an increase of over $682 million in capital spending over the 10-year plan.

Capital	Total 2020-2029 SPP $Millions	Total 2023-2032 SPP $Millions	Difference	Percent increase
Distribution - Feeder Hardening	$ 1,573	$ 2,027	$ 454.00	29%
Distribution - Lateral Hardening	$ 2,266	$ 2,931	$ 665.00	29%
Distribution - Self-Optimizing Grid (SOG)	$ 561	$ 340	$ (221.00)	-39%
Distribution - UG Flood Mitigation	$ 11	$ 14.50	$ 3.50	32%
Distribution - Vegetation Management	$ 497	$ 23	$ (474.30)	-95%
Transmission - Structure Hardening	$ 1,341	$ 1,603	$ 262.00	20%
Transmission - Substation Flood Mitigation	$ 27	$ 38	$ 11.00	41%
Transmission - Loop Radially Fed Substations	$ 52	$ 82	$ 30.40	58%
Transmission - Substation Hardening	$ 109	$ 133	$ 24.00	22%
Transmission - Vegetation Management	$ 198	$ 126	$ (72.00)	-36%
Total Capital	$ 6,635	$ 7,318	$ 682.60	10%

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

A. Yes. I looked at the ratio of capital spending to number of customers for the 2020-2029 SPP and the budget 2023-2031 SPP for the electric utilities who filed plans. This information is in the following table:

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

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

* FPUC and TECO's plan is dated 2022 for a 10-year period.

DEF's proposed spending per customer has increased more than 10% and the spending on a per customer basis shows DEF spending 150% more than that of some of the other utilities in Florida.

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

A. DEF and their consultant, Guidehouse, optimized the deployment plans based in part on "available resources." According to DEF, the only limit to the magnitude of the SPP budgets was the limitation of resources in terms of engineers and construction personnel realistically available to complete the annual goals of the program. It is as if DEF is racing to replace and harden as much of the plant as possible regardless of the impact to rate payers. I disagree that the only limitation on expenditures is based on availability of resources. The company should also consider the rate impact to customers and maintain a sharp focus on the ratio of the benefits to the costs. In my opinion the SPP for Tampa Electric and the other utilities is not reasonable and should be constrained to limit the rate impact on customers during a time of higher than average inflation.

III. SUMMARY OF PROPOSED SPP REDUCTIONS

Q. CAN YOU SUMMARIZE YOUR PROPOSED REDUCTION IN DEF'S PROGRAMS?

A. The table below summarizes my recommendations to reduce the 10-year SPP capital budget by $2.0 billion. These recommendations are detailed in the testimony.

Capital	Total 2023-2032 SPP $Millions	Reductions Proposed by Mara	Net 2023-2032 SPP $Millions	Reason for Reduction
Distribution - Feeder Hardening	$ 2,027	$ (500)	$ 1,527	Limit impact to customers
Distribution - Lateral Hardening	$ 2,931	$ (700)	$ 2,231	Limit impact to customers
Distribution - Self-Optimizing Grid (SOG)	$ 340	$ (340)	$ -	Does not comply with 25-6.030
Distribution - UG Flood Mitigation	$ 15	$ (15)	$ -	Does not comply with 25-6.030
Distribution - Vegetation Management	$ 23	$ -	$ 23	
Transmission - Structure Hardening	$ 1,603	$ (200)	$ 1,403	Does not comply with 25-6.030
Transmission - Substation Flood Mitigatio	$ 38	$ (38)	$ -	Does not comply with 25-6.030
Transmission - Loop Radially Fed Substati	$ 82	$ (82)	$ 0	Does not comply with 25-6.030
Transmission - Substation Hardening	$ 133	$ (133)	$ -	Does not comply with 25-6.030
Transmission - Vegetation Management	$ 126	$ -	$ 126	
Total Capital	$ 7,318	$ (2,008)	$ 5,310	

The reductions I am proposing will result in reducing the capital cost per customer to $2,856. To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table above should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order. I would recommend not including these programs in the updated SPP absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI

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

A. Yes, it does. However, the reduction in benefits must be balanced against the impact to the ratepayers. Currently, the United States is experiencing its worst inflation in 40 years and consumers have seen steep increases in the price of gas and groceries, as well as escalating electric bills specifically in Florida. Unless the Commission acts to limit the expenditures, the unchecked spending on SPP programs will result in an excessive burden on the rate payers.

DEF stated they did "not believe there are any implementation alternatives that could mitigate the rate impact without negatively impacting the benefits the SPP 2023 is designed to generate."[7] This may be true, but the benefits presented are based on a 30-year implementation duration. In my opinion, prioritizing feeders and laterals, poles, and other equipment that are the most vulnerable to extreme storms provides greater benefit in the early stages of the program.

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

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

[7] Direct Testimony of Brian M. Lloyd, p. 9, lines 4-8.

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

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

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

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

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

DEF's estimate for annual avoided restoration expenses for the 10-year SPP ranges from $56.5 million to $70.6 million.[8] Using these values, over a 5-year period the savings would be $282.5 million to $353 million but to achieve this savings DEF proposes to invest $7.3 billion for storm hardening over the next 10-years. Comparing this savings to actual costs incurred by DEF for 2016 to 2020, the net 5-year savings would be $282.5 million which means rate payers have to shoulder $751.97 million for storm costs plus the total capital cost of $7.3 billion contained in the SPP. In fact, DEF's SPP investment for the 10-year period is 1.82 times the total that all investor-owned utilities spent on storm restoration from 2016 to 2020. Thus, rate payers are paying more for the SPP and "reduced" storm costs than they would if the electric utilities did no storm hardening.

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

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

IV. THE REVIEW OF SPP PROJECTS

Q. CAN YOU DESCRIBE DEF'S FEEDER HARDENING PROGRAM?

[8] *See* Exhibit BML-2 p. 5 of 41.

A. Yes. The Feeder Hardening Program includes three sub-programs: Feeder Hardening, Pole Replacement, and Inspection. The Feeder Hardening sub-program is designed to upgrade the feeder backbone to the NESC 250C extreme wind load standard.[9] In addition, to structure strengthening, DEF proposes to increase lightning protection, upgrade conductors, relocate difficult to access facilities, address clearance encroachments, and replace oil-filled equipment within this sub-program.[10] The Pole Replacement and Inspection sub-programs are designed for the 8-year inspection cycle of most wood poles and replacement of the poles that fail inspection.

Q. CAN YOU EXPLAIN THE CLEARANCE ENCROACHMENTS?

A. Yes. This is new to DEF's 2023 SPP and is contained in DEF's Feeder Hardening sub-program. This is an additional scope of work for the Feeder Hardening sub-program and states that while upgrading feeders to the extreme wind load standards, the DEF will review clearances with non-company owned structures.[11] The reference to clearances are those clearances contained in the NESC between distribution conductors and buildings, signs, privately owned parking lot lights, antennas, and other non-company owned infrastructure.

Q. DO YOU AGREE WITH THE INCLUSION OF THIS NEW SCOPE OF WORK IN THE SPP?

A. No. When an electric utility builds a power line, the utility has a duty to maintain a safe distance from the buildings and other non-company owned structures. That safe distance is defined in the NESC. It is important to note the safe distances (i.e., clearances) in the

[9] *See* Exhibit BML-1, p. 7 of 56.
[10] *See* Exhibit BML-1, p. 7 of 56 and p. 8 of 56.
[11] *See* Exhibit BML-1, p. 7 of 56.

NESC to distribution lines and buildings, light poles, etc. have remained essentially unchanged since 1990.

If DEF built lines such that they are in violation of the NESC, that construction was imprudent, and DEF should be solely responsible for corrective actions. Alternately, if a customer installed a new sign, building, or non-company owned structure that encroached on the safe NESC clearances, then the individual customer should pay for the corrective action. One of the reasons electric utilities obtain exclusive easements is to protect the space around and below distribution lines such that the utility has legal grounds to compel the customer to pay for corrective actions or remove their facilities from the utility's easement.

For these reasons, it is obvious that DEF is responsible for correcting encroachment problems or otherwise obtaining funding from the customer who caused the encroachment. Thus, the cost for corrective actions to address clearance encroachments should be excluded from the SPP.

Q. WHAT IS THE MAGNITUDE OF THE DISTRIBUTION FEEDER HARDENING SUB-PROGRAM?

A. The ten-year expenditure budget for the feeder hardening sub-program is $1.8 billion in the 2023 SPP.[12] In comparison is same sub-program was budgeted for $1.5 billion in the 2020 SPP.[13]

Q. DO YOU HAVE A RECOMMENDATION FOR THE FEEDER HARDENING SUB-PROGRAM?

[12] *See* Exhibit KJM-2
[13] *See* Exhibit KJM-3p. 8 of 40.

A. Yes. I recommend the Feeder Hardening sub-program be held at the same level as the 2020 SPP for the 10-year period which is $1.5 billion. Below is a table of the annual budgets from the 2020 SPP and 2023 SPP for the Feeder Hardening sub-program.

	2020 SPP*		2023 SPP **			
	2021	2022	2023	2024	2025	2026
Sub-Program	**$ Million**	**$ Million**	**$ Million**	**$ Million**	**$ Million**	**$ Million**
Feeder Hardening	$ 60	$ 90	$ 143	$ 127	$ 151	$ 206

* Source Docket 20200069 Exhibit JWO-2 Page 9 of 40
** DEF response to OPC POD 1, Tab "SPP 2.0 10-year CapEx &OM

Essentially my recommendation caps the annual spending for this program to roughly $150 million per year. The benefits achieved with this budget would be the same level as suggested by DEF in the 2020 SPP which was $22 million to $28 million annually.[14] These benefits exceed the benefits suggested by DEF in the 2023 SPP of only $15 million to $18 million.

The benefits derived from the feeder hardening program are higher for the feeders most vulnerable and least ready for extreme wind conductions. Hardening these feeders first provides the highest benefit. The benefits of hardening will be reduced over time as the hardening sub-program is applied to feeders that are not as vulnerable to extreme wind and may have less tree cover or stronger poles already in place.

My recommendation is to reduce the budget for the Feeder Hardening sub-program by $500 million over 10-years and eliminate the scope of work related to encroachment problems.

Q. CAN YOU DESCRIBE DEF'S LATERAL HARDENING PROGRAM?

[14] *See* Exhibit KJM-3 p. 9 of 40.

A. Yes. This program will upgrade and harden branch line sections fed by the feeder backbone using four sub-programs: undergrounding laterals, lateral hardening overhead, pole replacement, and pole inspection.[15] The lateral undergrounding sub-program will be done on lateral segments that are the most prone to damage resulting in outages during extreme weather events.[16] The lateral hardening overhead sub-program includes structure strengthening, deteriorated conductor replacement, removing open wire secondary, replacing fuses with automated line devices, pole replacement, line relocation, and hazard tree removal.[17] The pole inspection and pole replacement sub-programs are part of DEF's 8-year cycle for inspection of wood poles and replacement of poles that fail inspection.[18]

Q. CAN YOU DESCRIBE WHAT IS MEANT BY THE TERM LATERAL?

A. Yes. The term lateral is critical to understanding the purpose of the Lateral Hardening Program. A distribution circuit can be described as a combination of the mainline feeder with laterals stemming off the mainline. The Feeder Hardening Program increases the strength of the mainline feeder from the substation to some point further along the circuit such as a three-phase tie point with another circuit. Some describe the feeder as the first zone of protection out of the substation, meaning the breaker in the substation will trip for any fault in this zone of protection. Thus, hardening the first zone of protection greatly reduces the chance of a structure failure during an extreme wind event. This is important since failure of the mainline feeder results in all customers on the feeder being without power. Laterals are taps off the mainline and DEF has over 11,800 miles of laterals on its system[19] compared to 6,300 miles of overhead feeders.[20] These laterals can be single-phase

[15] *See* Exhibit BML-1, p. 15 of 56.
[16] *See* Exhibit BML-1, p. 15 of 56
[17] *See* Exhibit BML-1, p. 15 of 56.
[18] *See* Exhibit BML-1, p. 18 of 56.
[19] *See* Exhibit BML-1, p. 18 of 56.
[20] *See* Exhibit BML-1, p. 9 of 56.

taps into residential neighborhoods or three-phase taps to subdivisions or businesses. Many of the laterals are behind the customers' premises. The Lateral Hardening Program focuses on improving the condition of the laterals so they may withstand an extreme wind event.

Q. WHAT IS THE MAGNITUDE OF THE DISTRIBUTION LATERAL HARDENING PROGRAM?

A. The ten-year expenditure budget for the lateral hardening program which includes undergrounding laterals, lateral hardening overhead, pole inspections and pole replacement is $2.9 billion in the 2023 SPP.[21] In comparison this same sub-program was budgeted for $2.2 billion in the 2020 SPP.[22]

Q. DO YOU HAVE A RECOMMENDATION FOR THE LATERAL HARDENING PROGRAM?

A. Yes. I recommended reducing the budgets for both the Lateral Undergrounding sub-program and the Lateral Overhead Hardening sub-program. I recommend the budgets for pole inspection and pole replacement in 2023 SPP not be changed. The 10-year combined budget for the Undergrounding and Lateral Hardening Overhead is $2.5 billion. I recommend a combined budget of roughly $1.8 billion.

	2020 SPP*		2023 SPP **			
	2021	2022	2023	2024	2025	2026
Sub-Program	**$ Million**	**$ Million**	**$ Million**	**$ Million**	**$ Million**	**$ Million**
Undergrounding and Lateral Hardening Overhead		$ 140.0	$ 160.4	$ 194.2	$ 226.2	$ 275.2

* Source Docket 20200069 Exhibit JWO-2 Page 14 of 40
** DEF response to OPC POD 1, Tab "SPP 2.0 10-year CapEx &OM

[21] *See* Exhibit BML-1, p. 18 of 56.
[22] *See* Exhibit KJM-3 p. 14 of 40.

Essentially my recommendation caps the annual spending for this program to roughly $180 million per year. The benefits achieved with this budget would be the same level as suggested by DEF in the 2020-2029 SPP which was $95 million to $119 million annually on a ten-year budget of $2.2 billion.[23] I am not conceding the correctness of or accepting DEF's calculation of the benefits but if we use DEF's own number, ten years of benefits to ten years' budget expenditures, the benefit to cost ratio is 0.50. These benefits exceed the benefit to cost ratio suggested by DEF in the 2023 SPP of $111 million to $139 million on $2.9 billion in spending which is a ratio of 0.44 or a 15% lower benefit to cost ratio.

Q. CAN YOU DESCRIBE DEF'S SELF-OPTIMIZING GRID (SOG) PROGRAM?

A. Yes. This program provides the devices, automation, and intelligence to provide the ability to a distribution feeder to automatically reroute power around damaged sections.[24] The system requires adjacent circuits to allow shifting of load from a faulted circuit to an operational circuit. The load shift helps to isolate a specific section of the faulted circuit. These systems require substation breakers and down-line reclosers or switches to have communication to a distribution system control (Yukon Feeder Automation System) and the devices must be able to operate remotely.

This program has a sub-program referred to as connectivity and capacity. This sub-program increases substation capacity and distribution line capacity to allow the SOG to automatically shift loads.

Q. DOES THIS SOG SYSTEM REDUCE RESTORATION COSTS?

[23] *See* Exhibit KJM-3 p. 14 of 40.
[24] See Exhibit BML-1, p. 27 of 56.

A. No. This system does not reduce the number of outages. Instead, the system is designed to limit the outage to the smallest segment of the system. For example, if a fuse is added to a lateral and a tree falls on that lateral, the fuse opens and isolates the failed portion of the system. Only a few customers are affected by the outage, but the repair costs to remove the tree off the line and perhaps replace a pole are the same whether a fuse is on the lateral or not. The SOG system is more complex but acts in a similar fashion in that it uses automation to switch and isolate outages to the smallest portion of the system. Thus, there is no reduction in restoration costs for the SOG system and the associated connectivity and capacity sub-program. In fact, DEF does NOT provide any costs associated with restoration costs.[25]

Q. DOES THIS SOG SYSTEM WORK DURING EXTREME WEATHER EVENTS?

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

On blue sky days, the SOG system should be very effective in reducing outages. But to meet Rule 25-6.030, F.A.C. a program shall have a "purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability."[26] DEF noted that the SOG would reduce customer minutes interrupted (CMI) in terms of system reliability and uses this value as a proxy for

[25] See Exhibit BML-1, p. 28 of 56.
[26] Rule 25-6.030 (2)(a), F.A.C.

extreme weather performance.[27] However, DEF has not provided any evidence the system will be a benefit during extreme weather events.

Q. WHAT IS YOUR RECOMMEDNATION REGARDING THE SELF-OPTIMIZING GRID PROGRAM?

A. Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would recommend this program with a ten-year budget of $340 million be eliminated from DEF's SPP because it fails to meet the purpose set forth in Rule 25-6.030(2)(a), F.A.C. This program, which only improves blue sky reliability, should be funded by means of standard base rate treatment.[28] To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

Q. CAN YOU DESCRIBE DEF'S UNDERGROUND FLOOD MITIGATION PROGRAM?

A. Yes. The program is designed to harden existing underground equipment prone to storm surge during extreme weather events.[29] For selected locations, DEF plans to utilize a concrete pad with increased weight, stainless steel tie downs and to change all connections

[27] *See* Exhibit BML-1, p. 28 of 56.
[28]- [Original language deleted per agreement.]
[29] *See* Exhibit BML-1, p. 32 of 56.

to waterproof (submersible) connections. In essence, DEF states that conventional switchgear will be replaced with submersible switchgear that are able to withstand storm surge.[30]

Q. CAN YOU EXPLAIN WHAT ARE SUBMERSIBLE SWITCHGEAR AND TRANSFORMERS?

A. Yes. Submersible means being able to withstand being underwater. The elbow connectors to connect medium voltage cable (15kV and 25kV cables) to switchgear are rated per IEEE Standard 386 to operate in 6 feet of water and therefore are submersible up to that depth.[31] Some switchgear like S&C PMH gear are air insulated and are not submersible. Many pad-mounted switchgear, even if they use oil insulation, SF6 gas, or solid dielectric insulation are not submersible because the control system (relays and SCADA communication) are typically not rated as submersible.

Submersible transformers are often used in vaults in downtown environments. Most single-phase pad-mounted transformers have exposed secondary bushings which do not make these units rated as submersible. There are some submersible single-phase transformers which are typically installed in vaults, but they are rarely used in the United States.

Q. HOW HAS DEF USED THIS PROGRAM IN 2021?

A. DEF replaced or modified 7 pieces of switchgear in 2021. Most of these were noted to have existing maintenance problems such as rust or oil leaks as shown in the following

[30] *Id.* at 6.
[31] IEEE 386-2016, IEEE Standard for Separable Insulated Connector Systems for Power Distribution Systems Rated 2.4 kV through 35 kV, Section 4.1.

table.[32] This does not appear to be flood mitigation but rather funding to replace aged switchgear with new switchgear. This type of replacement should more appropriately be recovered through base rates for that switchgear so that these units are not double counted. That is, the cost should not appear in both traditional rate base and in SPPCRC. I would recommend not including these programs in the updated SPP absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

Zone	Project	Sub Category	Project Status
South Coastal	GIP_LFSG_PMH-9_J229_J265	Submersible Switchgear	2020
North Coastal	SWITHGEAR RUSTED AND UNSAFE REPLACE IN NEW LOCATION	Submersible Switchgear	2021
North Coastal	Replace VFI switchgear RUSTED NOT SAFE TO WORK REPLACE IN PLACE	Submersible Switchgear	2021
South Coastal	REPLACE ESCO WITH G&W for RA 240	Submersible Switchgear	2020
South Coastal	(HOLD) GSR: SWG PME-9 L for Submersible REPLACEMENT SWG X2964 and X2965	Submersible Switchgear	2021
North Coastal	3/16 GIS*Replace VFI C5944 switchgear leaking oil	Submersible Switchgear	2020
North Coastal	3/8 GIS*Replace VFI C5928 seeping oil.	Submersible Switchgear	2020

DEF also stated they installed 24 submersible transformers in the Dixie Shore subdivision. Homes in this portion of this subdivision with underground electric service were built in the early 1970s.[33] These units may likely be live-front single-phase transformers being replaced with new standard dead-front transformers which are not submersible transformers. These are not upgrades to submersible transformers but rather the standard single-phase transformer used by DEF. Thus, these replacements are just aging infrastructure replacements and therefore should be recovered in base rates. I would

[32] *See* Exhibit KJM-3.
[33] Citrus County Tax Assessor Office.

recommend not including these replacements in the updated SPP absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

Q. ARE THE SWITCHGEAR BEING REPLACED BY THIS PROJECT RATED AS SUBMERSIBLE?

A. No. DEF is using VFI switchgear, PME-9 switchgear, and G&W switchgear which are not submersible units. These units use elbow connectors that are rated submersible, but have electronic controls that are not submersible, and PME-9 uses air-insulated bus work which is not rated submersible. Based on the available information, I also believe the transformer replacement at Dixie Shores is simply an aging infrastructure replacement from live-front to dead-front single-phase transformers. I note that the 2023 planned project for Floramar is in an area that was built in late the 1960s and early 1970s and is likely to also have live-front transformers.

Q. WHAT IS YOUR RECOMMENDATION FOR THE UNDERGROUND FLOOD MITIGATION PROGRAM?

A. Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would recommend eliminating this program which is budgeted for $14.5 million for the 10-year period of the 2023 SPP.[34] It is obvious to me that DEF is proposing to use this SPP program to fund replacement of aging infrastructure. It is true that any new equipment will help with reliability. However, replacement of aging equipment is a core function of DEF in providing service to customers. The equipment being installed is presumably DEF's current standard equipment for coastal construction and not an upgrade that reduces storm restoration costs or customer outage times. Without a clear

[34] *See* Exhibit KJM-2.

improvement in resiliency, the project does not meet the requirements of Rule 25-6.030(3)(a), F.A.C.[35] Therefore, absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would recommend this program be excluded from the SPP. To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

Q. CAN YOU DESCIRBE THE STRUCTURE HARDENING PROGRAM?

A. Yes. The Structure hardening program is part of DEF's functional group of programs related to the transmission system. The Structure Program is then broken down further to seven sub-programs including:

1. Wood Pole Program,
2. Structure Inspections (O&M),
3. Gang Operated Air Break Switch Automation,
4. Tower upgrade,
5. Tower Drone Inspection (O&M),
6. Tower Cathodic Protection, and
7. Overhead Ground wire (OHGW).

The current 10-year budget for this program is $1.6 billion.[36]

[35] Rule 25-6.030(3)(a), F.A.C.
[36] *See* Exhibit KJM-2.

Q. CAN YOU DESCRIBE THE TOWER UPGRADE SUB-PROGRAM?

A. Yes, the Tower Upgrade sub-program contains upgrade activities which will replace tower types that have previously failed during extreme weather events. Seven hundred (700) such towers have been identified. The sub-program also includes replacement of lattice towers identified from visual ground inspections, aerial drone inspections and data gathered during cathodic protection installations.[37]

Q. DO YOU HAVE AN OPINION ON THE NEED TO REPLACE TOWER TYPES THAT HAVE PREVIOUSLY FAILED?

A. Yes. DEF notes that some tower designs have failed in previous extreme wind events.[38] In DEF's 2020-2029 SPP, this sub-program was focused on the replacement of towers identified though enhanced engineering inspections of towers similar in age and vicinity as the towers that failed during Hurricane Irma.[39] First, transmission lines have been required by the NESC to be built for extreme wind events since at least 1977.[40] Failure due to a design flaw should not be a SPP activity. If DEF owns towers that fail to meet strength requirements when constructed, then replacement costs should not be considered an "upgrade" and therefore should not be funded through the SPP, absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI. Second, if age is a criterion and the towers are beyond their useful life, then replacement of the towers is an aging infrastructure project and therefore should not be included in the SPP, absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-

[37] *See* Exhibit BML-1, p. 38 of 56.
[38] *See* Exhibit BML-1, p. 38 of 56.
[39] *See* Exhibit KJM-5 p. 30-34.
[40] 2017 NESC Handbook, Fourth Edition, IEEE Standard Press, August 1, 2016 ("NESC").

EI. Replacing towers with new towers that meet the same weather loading condition will not add to resiliency. If the tower design was flawed, it would have been imprudent for DEF to accept the design and construction of the tower in which case the cost should also be excluded from the SPP, absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

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Q. WHAT ABOUT REPLACEMENT OF OLD LATTICE TOWERS, SHOULD THESE BE INCLUDED IN THE SPP?

A. No. Replacing a tower with another tower of the same strength does not increase resiliency. Rather it simply maintains the status quo in terms of strength. In order to meet Rule 25-6.030, F.A.C., a program shall have a "purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions therefore improving overall service reliability."[41]

Clearly replacing new towers with the same strength and same materials is not a clear improvement in outage costs or times, therefore, the project does not meet the requirements of Rule 25-6.030(3)(a), F.A.C.[42]

I would recommend that this sub-program with $175 million 10-year budget[43] be eliminated from the SPP, absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI. To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown

[41] Rule 25-6.030 (2)(a), F.A.C.
[42] Rule 25-6.030 (3)(a), F.A.C.
[43] *See* Exhibit KJM-2.

in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

Q. CAN YOU DESCRIBE THE CATHODIC PROTECTION SUB-PROGRAM?

A. Yes, the sub-program is designed to limit corrosion of the lattice tower system.[44] Steel components can be weakened from electrolysis which slowly takes metal away from the structure. A passive corrosion protection method can be used to help reduce or slow this electrolysis.[45]

Q. DOES THIS SUB-PROGRAM INCREASE THE STRENGTH OF TOWERS ON DEF'S SYSTEM?

A. No. The passive corrosion sub-program limits the strength reduction. When the strength of a tower or structure decays below a certain level, per the NESC, the structure must be replaced or rehabilitated.[46] Thus this sub-program does not increase strength or improve resiliency. The purpose of this project, in my opinion, is to increase the service life of the tower which has value but does not meet the requirements in Rule 25-6.030(3)(a), F.A.C., for reducing outage restoration costs and reducing outage times. The tower will have the same required strength throughout its service life and should therefore withstand the extreme wind for which it is designed. The cathodic protection does not add strength, it only extends the life of the asset. Therefore, absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, in my opinion, this sub-program which has a 10-year budget of $25 million[47] should be excluded from the SPP.

[44] *See* Exhibit BML-1 page 38 of 56.
[45] *Id.*
[46] *See* NESC, Table 253-1.
[47] *See* Exhibit KJM-2.

To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

Q. CAN YOU DESCRIBE THE OVERHEAD GROUND WIRE (OHGW) SUB-PROGRAM?

A. Yes, the sub-program replaces deteriorated overhead ground wires. DEF proposes installing a new OHGW equipped with a fiber optic cable imbedded in the OHGW.[48]

Q. DOES THIS SUB-PROGRAM OF REPLACING OHGW IMPROVE RESILIENCY AND REDUCE RESTORATION COSTS?

A. No. DEF has a duty to maintain its systems within the strength requirements of the NESC. If the OHGW is deteriorated, then it needs to be replaced. The replaced conductor does not add strength or resiliency compared to the original well-maintained structure. Thus, there will be no reduction in outage restoration costs and no reduction in the outage times. This is simply an aging infrastructure replacement sub-program. DEF is adding fiber optic OHGW which adds communication capabilities which may or may not be used. In fact, from my experience, most new transmission lines have fiber optic OHGW installed as standard design. For fiber optic cable to be used and useful it must be integrated into a system of fiber optic cables and have data flowing over the newly installed fiber optic

[48] *See* Exhibit BML-1 page 40 of 56.

cable. The focus of the sub-program is replacing deteriorated OHGW. Fiber Optic OHGW is a minor side benefit.

Q. WHAT IS YOUR RECOMMENDATION FOR THE OVERHEAD GROUND WIRE SUB-PROGRAM?

A. Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would recommend eliminating this sub-program which is budgeted for $138.5 million for the 10-year period of the 2023 SPP. [49] The sub-program does not meet the requirements in Rule 25-6.030(3)(a), F.A.C. for reducing outage restoration costs and reducing outage times. The new OHGW will meet the same NESC loading limits for extreme wind so there is no increase in strength and thus no reduction in restoration costs. To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

Q. CAN YOU DESCRIBE THE GANG OPERATED AIR BREAK (GOAB) AUTOMATION SUB-PROGRAM?

A. Yes, this sub-program is a 20-year initiative to upgrade 160 switch locations with modern switches enabled with SCADA communication and remote-control capabilities. The existing GOAB switches must be manually operated. By automating the switches, DEF

[49] *See* Exhibit KJM-2.

will be able to remotely control the transmission system in order to perform equipment maintenance or isolate trouble spots to minimize impacts to customers.[50]

Q. DOES THIS GOAB SUB-PROGRAM REDUCE OUTAGES OR RESTORATION COSTS?

A. No. This system does not reduce the number of outages. Similar to my discussion regarding the SOG program, the GOAB sub-program uses automation to switch and isolate outages to the smallest portion of the system. Thus, there is no reduction in restoration costs with the installation of the GOAB sub-program. In fact, DEF does not provide specific restoration cost reduction associated with this program.[51]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE GOAB SUB-PROGRAM?

A. Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would recommend this program with a ten-year budget of $72.5 million[52] be eliminated from DEF's SPP because it fails to meet the purpose set forth in Rule 25-6.030(3)(a), F.A.C. which requires programs to reduce restoration costs and to reduce outage times. This program does not reduce restoration costs and therefore should be funded by means of standard rate base treatment. To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown

[50] *See* Exhibit BML-1, p. 39 of 56.
[51] See Exhibit BML-1, p. 41 of 56.
[52] *See* Exhibit KJM-2.

in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

Q. CAN YOU DESCRIBE DEF'S SUBSTATION FLOOD MITIGATION PROGRAM?

A. Yes, this program is designed to build in protection for substations most vulnerable to flood damage according to flood plain maps and storm surge data.[53]

Q. WHAT IS YOUR UNDERSTANDING OF BUILDING A SUBSTATION IN COASTAL FLOOD ZONES?

A. The acquisition of land for a substation is always a challenge but the land needs to be suitable for safe and reliable electric service. Flood maps were not issued until 1973[54] so substations constructed before 1973 would not have had standards requiring certain elevations. However, stations built after 1973 should have been designed with the knowledge of potential flood waters and designs should have accounted for this predictable occurrence. Specifically, the standard *ASCE-24-14 Flood Resistant Design and Construction* calls for the facilities to be designed for the Basic Flood Elevation (100-year flood level) plus two feet. Details of improvements are not required to be contained in the current SPP. Therefore, no conclusion can be reached regarding the prudence of the original design and the proposed mitigation plans.

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

[53] *See* Exhibit BML-1, p. 47 of 56.
[54] See Exhibit KJM- 6

A. Yes. It is my belief that most of DEF's distribution system is designed for a single contingency failure which would be consistent with modern distribution systems in suburban and urban areas. Single contingency means designing for the loss of one feeder or one substation transformer. Thus, if a transformer had to be de-energized for flooding it is very likely that the load from this substation can be switched to an adjacent substation that is not flooded. To the extent this is the case, then the Substation Flood Mitigation Program does not reduce outage time nor restoration costs and therefore should be excluded from the SPP in accordance with the statute that contemplates reduction in both outage time and restoration costs. I would recommend not including these programs in the updated SPP absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

Q. TO YOUR KNOWLEDGE HAS DEF SUFFERED OUTAGE TIME DUE TO FLOODING OF ITS SUBSTATIONS?

A. My understanding is DEF has not had any outages due to flooding of its substations in recent years. There was one instance where sandbags were deployed at a control house but there were no outages.[55]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SUBSTATION FLOOD MITIGATION PROGRAM?

A. Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would recommend inclusion of this program on a limited basis. The program should exclude any substation where there are alternate feeds to allow the substation to be de-energized due to flooding. The program should also exclude any

[55] *See* Exhibit KJM-7.

substation that has not had a history of flooding or which a flooding threat cannot be demonstrated. The excluded cost is likely the entire 10-year budget of $38 million.[56] To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

Q. CAN YOU DESCRIBE DEF'S LOOP RADIALLY-FED SUBSTATIONS PROGRAM?

A. Yes. This program is designed to convert radially fed substations to networked substations and will target 17 sites over 20 years.[57] The program constructs a second feed to substations that DEF determines are more likely to experience long outage durations during extreme weather events. This work may include upgrades to existing substations.

Q. DID DEF INCLUDE ANY COST REDUCTION FOR THIS PROGRAM?

A. No. There is no outage cost reduction for this program and in fact DEF does not provide any estimates for outage cost reduction.[58] Essentially, if the backup transmission line has to be used it is because the primary transmission feed is damaged. Repairs still need to be made to the primary transmission feed. Thus, this program projected to spend $206 million

[56] *See* Exhibit BML-1, p. 47 of 56.
[57] *See* Exhibit BML-1, p. 49 of 56.
[58] *See* Exhibit BML-1, p. 49 of 56.

over 20 years does not reduce storm restoration costs, and according to DEF, only results in a 10% reduction in customer outage hours.[59]

Q. DO YOU BELIEVE THIS PROGRAM SHOULD BE INCLUDED IN THE SPP?

A. Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would say no. The priority should be to harden transmission lines with non-wood poles designed for extreme wind. With such a design the likelihood of transmission failure is greatly reduced and the need for a loop transmission feed is eliminated. Storm hardened transmission structures have shown to be extremely resilient. For example, FPL reported that zero hardened transmission poles failed in Hurricane Matthew or Hurricane Irma.[60] Thus if DEF puts a higher priority on strengthening the radial taps, the proposed looped transmission lines are not necessary to achieve storm hardening.

Q. WHAT IS YOUR RECOMMENDATION REGARDING LOOP RADIALLY-FED SUBSTATIONS PROGRAM?

A. Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would recommend eliminating this program, which has a 10-year budget of $82.4 million,[61] from the SPP. The program fails to meet one criterion of Rule 25-6.030, F.A.C. which is that this program does not reduce restoration costs. To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending

[59] *See* Exhibit BML-1, p. 49 of 56.
[60] Docket No. 20220051-EI, FPL Exhibit MJ-1, Appendix A, p. 7 of 18.
[61] *See* Exhibit KJM-2.

rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

Q. CAN YOU DESCRIBE DEF'S SUBSTATION HARDENING PROGRAM?

A. Yes, this program upgrades oil breakers and electromechanical relays. The program is designed to eliminate 80 oil breakers and 140 electromechanical relay groups with digital relays in the 10-year period of the SPP.[62]

Q. DOES THIS SUB-PROGRAM OF SUBSTATION HARDENING IMPROVE RESILEINCY AND REDUCE RESTORATION COSTS?

A. No. This program is more about replacing aging infrastructure than it is a storm hardening program. The existing oil breakers open and clear faults. The new breakers will open and clear faults. If the existing breakers cannot safely operate and avoid catastrophic failure these devices should, based on prudent utility practice, be replaced. Thus, in terms of performance on the system there would be no significant change other than using modern breakers. These upgraded breakers do not reduce restoration costs and also do not reduce outage times. Existing relays are electromechanical relays which are not readily available in the electric industry because they are considered obsolete. All new substations and relay replacement projects throughout the industry use the modern digital relays. So, while, the digital relays are superior to electro-mechanical relays, DEF realistically has no choice but to replace an electro-mechanical relay with a digital relay, regardless of the threat of extreme weather. Thus, this program is replacing older equipment that is at or near obsolescence with modern equipment. DEF suggests that upgrading to digital relays with

[62] *See* Exhibit BML-1, p. 52 of 56.

advanced system protection functions and communication will enable DEF to respond and restore service more quickly in the aftermath of extreme weather events. However, this does not change the fact that outages will still occur and the cost to restore those outages will not be reduced. Therefore, the program does not meet the criteria set forth in Rule 25-6.030, F.A.C.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SUBSTATION HARDENING PROGRAM?

A. Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would recommend this $133 million[63] program be eliminated from the SPP. The need to replace aging infrastructure does not change but the SPP is specifically designed for those projects that reduce outage times and restoration costs. DEF's estimate for reduction in restoration costs by $90,000 to $120,000 annually is insignificant compared to the program costs. While I may disagree with DEF's assessment of reduction in restoration costs, since the program is actually about replacing old equipment, the benefit to cost ratio for this program (using the company's proposed savings) over a ten-year period in its best light is less than 1%.[64] To the extent that this portion of my testimony containing my expert opinion is superseded by a stipulation approved by the Commission in Order No. 2021-0202A-AS-EI, my testimony should not form the basis for an adjustment. Specifically, the portions of my testimony recommending rejection of programs or subprograms under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 should not be considered for the rate recovery years 2023 and 2024 where they conflict with the provisions of this order.

[63] *See* Exhibit KJM-2.
[64] 10 years of benefit at $90,000 per year divided by total program costs of $133 million.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

BY MR. REHWINKEL:

Q Mr. Mara, did you also cause to be prepared seven exhibits, KJ -- KMJ through -- KJM-1 through KJM-7?

A Yes, I did.

Q And those have been identified as Exhibits 24 through 30 in the CEL?

A Yes.

MR. REHWINKEL: Thank you, Mr. Chairman. We will move to the Tampa Electric docket.

CHAIRMAN FAY: Okay. Ms. Wessling, you are recognized.

MS. WESSLING: Thank you.

EXAMINATION

BY MS. WESSLING:

Q All right. Would you please state your full name and your business address for the record?

A Kevin Mara, 1850 Parkway Place, Marietta, Georgia.

Q All right. And with regard to Docket No. 20220048, on whose behalf are you testifying?

A Office of Peoples Counsel.

Q Public Counsel?

A Public Counsel.

Q Okay. And have you previously been sworn in

this case?

A I have.

Q All right. Did you cause to be filed prefiled direct testimony consisting of 30 pages in the Docket 20220048?

A I did.

Q All right. And do you have any corrections to your testimony?

A I do not.

Q If I were to ask you the same questions today, would your answers be the same?

A They would.

MS. WESSLING: Mr. Chair, I would ask that Mr. Mara's testimony be entered into the record as though read.

CHAIRMAN FAY: Okay. Show it inserted.

(Whereupon, prefiled direct testimony of Kevin J. Mara in Docket No. 20220048 was inserted.)

DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20220048-EI

I. INTRODUCTION

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

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

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

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

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

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

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

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

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

- Vermont Department of Public Service
- Florida Public Service Commission

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

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

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

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

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

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

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

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

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

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

II. REVIEW OF THE PURPOSE OF STORM HARDENING

Q. PLEASE DISCUSS SECTION 366.96, FLORIDA STATUTES.

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

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

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

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

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

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

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

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

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

(1) Reduce restoration costs, and

(2) Reduce outage times.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. SUMMARY OF PROPOSED SPP REDUCTIONS

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

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

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

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

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

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

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

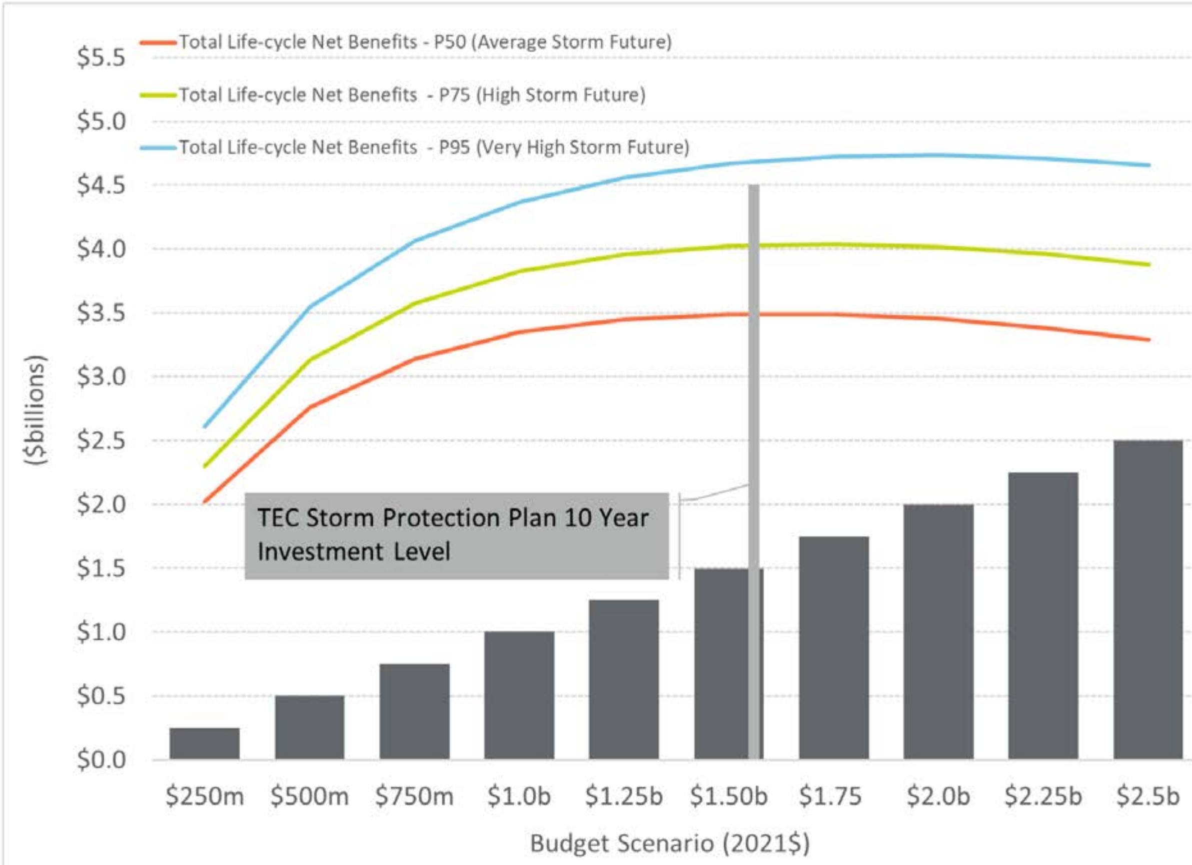
result from unchecked spending on SPP programs unless the Commission acts to limit the expenditures.

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

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

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

Figure 6-1: Budget Optimization Results



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

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

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

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

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

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

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

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

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

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

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

IV. <u>REVIEW OF SPP PROJECTS</u>

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. CAN YOU EXPLAIN THE DISTRIBUTION LATERAL UNDERGROUNDING PROGRAM?

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

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

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

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

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

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

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

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

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

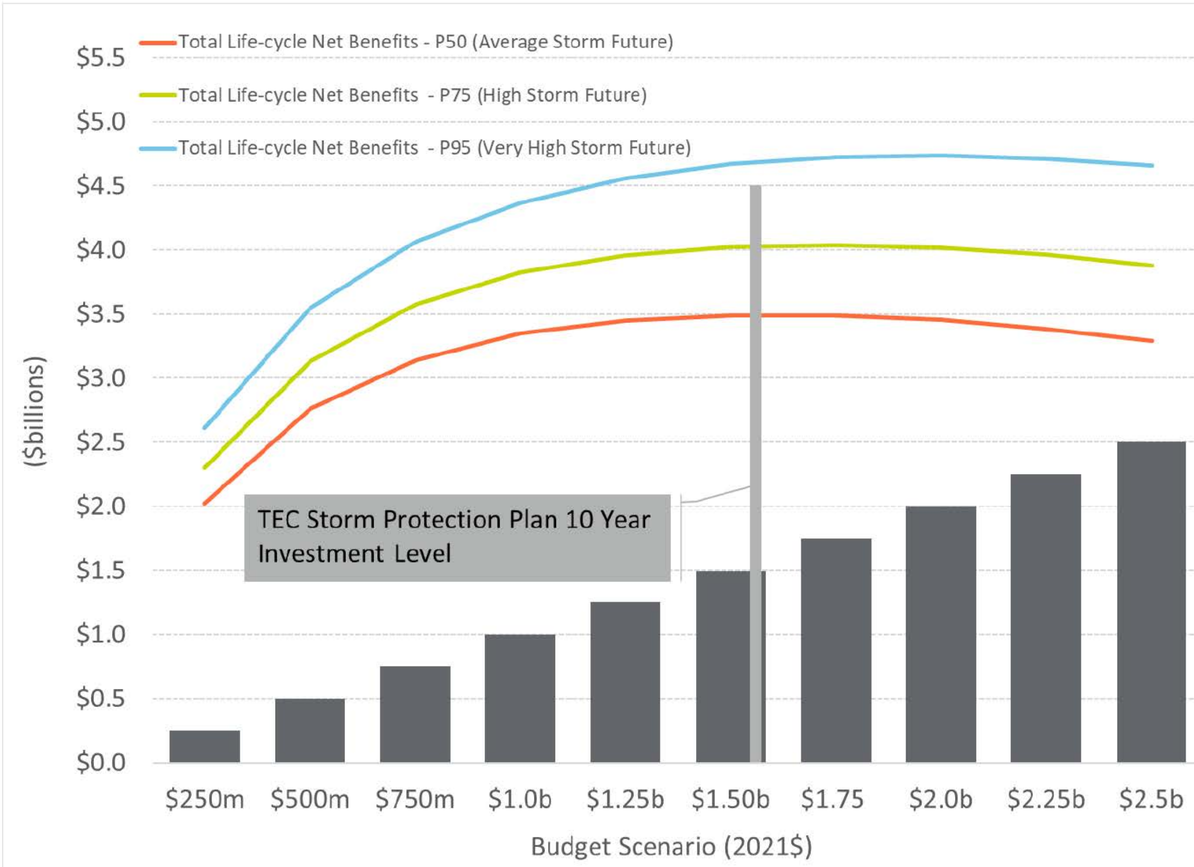
A. No. The statute does not prescribe the pace for storm hardening. This is left to the utilities to determine. Of course, more undergrounding means better resiliency, but this must be balanced with the cost impact to the customers. Tampa Electric's capital expenditures for the 2020-2029 SPP 10-year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

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

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

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

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



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

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

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

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

Q. CAN YOU EXPLAIN THE TRANSMISSION ACCESS ENHANCEMENT PROGRAM?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

BY MS. WESSLING:

Q Mr. Mara, did your prefiled testimony have seven exhibits attached labeled KJM-1 through KJM-7?

A Yes, it did.

Q All right. And do you have any corrections to make though those exhibits?

A I do not have any corrections.

Q Thank you.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good afternoon, Mr. Mara.

A Good afternoon.

Q Can you please state your name and business address for the record in Docket 20220049-EI?

A My name is Kevin Mara. Business address is 1850 Parkway Place, Marietta, Georgia.

Q Did you cause to be prefiled direct testimony consisting of 33 pages in Docket No. 20220049-EI?

A Yes, I did.

Q Do you have any corrections to your testimony?

A No, I do not.

Q And if I were to ask you those same questions today, would your answers be the same?

A Yes.

MS. CHRISTENSEN: I would ask that Mr. Mara's testimony be entered into the record as though read.

CHAIRMAN FAY: Show it entered.

(Whereupon, prefiled direct testimony of Kevin J. Mara in Docket No. 20220049 was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of 2022-2031 Storm Protection Plan, pursuant to Rule 25-6.030, F.A.C., Florida Public Utilities Company.	DOCKET NO.: 20220049-EI FILED: May 31, 2022

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DIRECT TESTIMONY

OF

KEVIN J. MARA, P.E.

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

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DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 20220049-EI

I. INTRODUCTION

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

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

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Electrical Engineering from Georgia Institute of Technology in 1982. Between 1983 and 1988, I worked at Savannah Electric and Power as a distribution engineer designing new services to residential, commercial, and industrial customers. From 1989-1998, I was employed by Southern Engineering Company as a planning engineer providing planning, design, and consulting services for electric cooperatives and publicly owned electric utilities. In 1998, I, along with a partner, formed a new firm, Hi-Line Associates, which specialized in the design and planning of electric distribution systems. In 2000, Hi-Line Associates became a wholly owned subsidiary of GDS Associates, Inc. and the name of the firm was changed to Hi-Line Engineering, LLC. In 2001, we merged our operations with GDS Associates, Inc., and Hi-Line Engineering became a department within GDS. I serve as the Principal Engineer for Hi-Line Engineering and am Executive Vice President of GDS Associates. I have field experience in the operation, maintenance, and design of transmission and distribution systems. I have performed numerous planning studies for electric cooperatives and municipal systems. I have prepared short circuit models and overcurrent protection schemes for numerous electric utilities. I have also provided general consulting, underground distribution design, and territorial assistance.

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

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

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associations of customers, and government agencies.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

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

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

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

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

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

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

A. I am presenting my recommendations on behalf of OPC regarding FPUC's proposed 2022-2031 Storm Protection Plan. My testimony serves to refute the testimony presented by Mr. P. Mark Cutshaw regarding the scope of the SPP projects, and whether the programs and projects could qualify to be included in the SPP.

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

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

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Q. PLEASE SUMMARIZE YOUR TESTIMONY.

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

I. THE REVIEW OF PURPOSE OF STORM HARDENING

Q. PLEASE DISCUSS SECTION 366.96, FLORIDA STATUTES.

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

The Florida Legislature has directed the Commission to consider "[t]he estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan."[2] But there is no express ceiling or cap on the magnitude of the upgrades or improvements contained in the SPP or on the rate impact to the customers. Again, while the legislature left the ratemaking impact of both of these considerations to the Commission's discretion it appears that they

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

gave the Commission direction and the tools to limit the utilities' spending in the SPP and SPPCRC approvals. As part of my testimony, I will present some recommended limits to the construction programs.

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

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

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

[3] Rule 25-6.030 (2)(a), F.A.C.

reducing restoration costs and reducing outage times associated with extreme weather conditions . . . "[4]

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

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

Thus, there are two criteria that must be in each SPP project;

(1) Reduce restoration costs, and

(2) Reduce outage times.

Rule 25-6.030, F.A.C., requires utilities to provide budgets for programs and to provide the estimated reduction in restoration costs.[5] These amounts must be balanced against the benefits to the utilities' customers. Further, the two amounts will allow the Commission and stakeholders to understand the benefits of the capital investments for storm hardening relative to the "reasonableness" of the costs. Any program can claim to reduce outage costs and outage time; however, the program must be cost effective for customers to benefit. To summarize, the

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

Rules require a two-prong test for consideration of a program: reduction in outage costs and reduction in outage time.

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

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

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

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

due the superior ability of the non-wood poles to survive during extreme windstorms.

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

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

A. Yes. Adding new sectionalizing equipment such as smart gird enhancements, SCADA systems and remotely operated air break switches (GOABs) do not reduce outages. The outage will still occur and will still need to be repaired. Thus, there is no change to the restoration costs. These devices only help to isolate a smaller portion of the system that is affected by the outage. Thus, the devices fail to meet the criteria in Rule 25-6.030, F.A.C. While the devices do reduce outage times, they fail to reduce outage costs. Further, adding sectionalizing equipment does not strengthen or harden the system.

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

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

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

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

A. Section 366.96, Florida Statutes, and Rule 25-6.030, F.A.C., provide no overt governance regarding limitations to the costs of SPP programs. It is imperative that the Commission consider guidelines to limit the magnitude of each program's costs compared to its benefits. For this reason, and on behalf of the customers who must bear these costs against the level of projected benefits, elsewhere in my testimony, I propose my limits to projects for the Commission to consider in the public interest.

Q. DID FPUC PROVIDE ANY SPECIFIC COST REDUCTION FOR THE PROGRAMS PROPOSED IN THE 2022-2031 SPP?

A. No. FPUC did not include any estimate of the cost reduction of the programs. Mr. Cutshaw stated the FPUC's SPP included an estimate of the resulting reduction outage times and restoration costs due to extreme weather conditions.[7] This information is specifically required by Rule 25-6.030(3)(d)1, F.A.C. The Rule further requires a comparison of the costs of the programs and the benefits of the programs.[8] Without an estimate of the cost reduction for outages, it is impossible for any party to make a judgment on prudence. FPUC acknowledged that the Commission shall consider FPUC's SPP based on the estimated costs and benefits to the utility and its customers of making improvements proposed in the plan.[9] Mr. Cutshaw states that the programs meet the statutory objective of reducing restoration costs.[10] Yet nowhere in the 2022-2031 SPP does FPUC provide anything other than vague language about reducing restoration costs. In my opinion, anyone can claim reduction in outage restoration costs, but in a regulatory setting with the need to comply with specific statues, it is necessary and expected

[7] Direct Testimony of P. Mark Cutshaw, p. 8, lines 20-23.
[8] Rule 25-6.030 (3)(d)3 and Rule 25-6.030 (3)(d)4, F.A.C.
[9] FPUC's Petition for Approval of Storm Protection Plan, p. 4.
[10] Direct Testimony of P. Mark Cutshaw, p. 4, lines 11-12.

that monetized values of these reductions during extreme weather events be provided.

Q. DID FPUC PROVIDE ANY SPECIFIC REDUCTIONS IN OUTAGE TIMES FOR THE PROGRAMS PROPOSED IN THE 2022-2031 SPP?

A. No. FPUC did not include any estimate of the reduction in outage times. Even though Rule 25-6.030 (3)(d)1, F.A.C., mandates "including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions." I believe that the outage times should be monetized on a basis consistent with the other utilities to help determine the benefits compared to the costs of the proposed storm hardening programs. FPUC simply states in many of the programs that "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.'"[11] This is inadequate for the Commission to make a proper determination. There is no cost reduction estimate provided; only a statement of belief by FPUC. In fact, FPUC used exactly the same statement for the Overhead Feeder Hardening Program, Distribution Pole Inspection and Replacement Program, Transmission Wood Pole Replacement Program, and T&D Vegetation Management Program.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE LACK OF INFORMATION REGARDING THE REDUCTION IN OUTAGE COSTS AND REDUCTION IN OUTAGE TIME?

[11] *See* FPUC Storm Protection Plan, p. 26.

A. I recommend that FPUC be required to amend their filing and provide the necessary data for each program as required by Rule 25-6.030 F.A.C., with an opportunity for intervenors to provide review and testimony.

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

A. No. FPUC's 2022-2031 SPP is the Company's first filing of an SPP so I was unable to make a comparison to the budgets of a prior plan.

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

A. Yes. I looked at the ratio of capital spending to the number of customers for FPUC's 2022-2031 SPP and the 10-year SPPs for the other electric utilities who filed plans. This information is in the following table:

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

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

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

FPUC's spending per customer is extremely high when compared to the other utilities in Florida. In fact, the spending on a per customer basis is more than 3.5

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times higher than Tampa Electric, the next smallest utility. This higher cost per customer will result in an excessive increase in rates for all FPUC customers.

II. SUMMARY OF PROPOSED SPP REDUCTIONS

Q. CAN YOU SUMMARIZE YOUR PROPOSED REDUCTION IN FPUC'S PROGRAMS?

A. The table below summarizes my recommendations to reduce the 10-year SPP capital budget by $2.0 billion. These recommendations are detailed in the testimony.

Capital	Total 2022-2031 SPP $Millions	Reductions Proposed by Mara	Net 2022-2031 SPP $Millions	Reason for Reduction
Distribution - OH Feeder Hardening	$ 17.1	$ -	$ 17.1	
Distribution - OH Lateral Hardening	$ 24.7	$ (12.6)	$ 12.1	Limit impact to customers
Distribution - OH Lateral Underground	$ 63.3	$ (31.1)	$ 32.2	Limit impact to customers
Distribution - Pole Insp. & Replace	$ 12.6	$ -	$ 12.6	
T&D - Vegetation Management	$ -	$ -	$ -	
Future T&D Enhancements	$ 30.0	$ (30.0)	$ -	Does not comply with Rule 25-6.030
Transmission / Substation Resiliency	$ 86.1	$ (86.1)	$ -	Not prudent
Transmission - Inspection and Hardening	$ 7.1	$ -	$ 7.1	
SPP Program Management	$ 2.2	$ -	$ 2.2	
Total Capital	$ 243.1	$ (159.8)	$ 83.4	

The reductions I am proposing will result in reducing the capital cost per customer to $2,528 which is still higher than most of the larger utilities in Florida.

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

A. Yes, it does. However, the reduction in benefits must be balanced against the impact to the rate payers. In fact, the United States is experiencing its worst inflation in 40 years and consumers have seen steep increases in the price of gas and groceries, as well as escalating electric bills specifically in Florida. Unless the Commission acts to limit the expenditures, the unchecked spending on SPP programs will result in an excessive burden on the ratepayers.

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

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

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

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

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

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

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

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

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

III. THE REVIEW OF SPP PROJECTS

Q. CAN YOU DESCRIBE FPUC'S OVERHEAD LATERAL HARDENING PROGRAM?

A. Yes. This program is intended to upgrade certain laterals to NESC 250C Extreme wind standards. The upgrades include replacement of deteriorated poles, relocation of facilities to accessible areas, upgrade the conductor to one of higher tensile strength, adequate BIL insulation, additional guying, environmental upgrades such as avian protection and animal mitigation, and upgrading fuses to reclosers.[12] The priority for laterals to be hardened is based on a Risk Resiliency Model.

Q. CAN YOU DESCRIBE WHAT IS MEANT BY THE TERM LATERAL?

[12] *See* FPUC Storm Protection Plan, p. 27.

A. Yes. The term lateral is critical to understanding the purpose of the Overhead Lateral Hardening and Overhead Lateral Undergrounding. A distribution circuit can be described as a combination of the mainline feeder with laterals stemming off the mainline. The Overhead Feeder Hardening Program increases the strength of the mainline feeder from the substation to some point along the circuit such as a three-phase tie point with another circuit. Some describe the feeder as the first zone of protection out of the substation, meaning the breaker in the substation will trip for any fault in this zone of protection. Thus, hardening the first zone of protection greatly reduces the chance of a structure failure during an extreme wind event. This is important since failure of the mainline feeder results in all customers on the feeder being without power. Laterals are taps off the mainline and FPUC has approximately 575 miles of overhead lateral lines of which are 433 miles are single phase lines.[13] For FPUC's system a typical lateral can have upwards of 200 to 300 customers.[14] These laterals can be single-phase taps or three-phase taps serving residential neighborhoods or businesses. The Overhead Lateral Hardening Program focuses on improving the condition of the laterals so they may withstand an extreme wind event.

Q. WHAT IS THE MAGNITUDE OF THE OVERHEAD LATERAL HARDENING PROGRAM?

[13] *See* FPUC Storm Protection Plan, p. 27 and p. 28.
[14] *See* FPUC Storm Protection Plan, p. 27.

A. The ten-year capital budget for the FPUC Overhead Lateral Hardening program is $24.75 million in the 2022-2031 SPP.[15]

Q. DID FPUC PROVIDE ANY SPECIFIC VALUE FOR THE BENEFITS OF THE OVERHEAD LATERAL HARDENING PROGRAM?

A. No. Even though this data was required in the filing by Rule 25-6.030, F.A.C., FPUC failed to provide any estimates of cost reduction or estimates of outage reduction times.[16] FPUC referenced a report prepared by the Florida PSC entitled *Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018,* dated July 2018. FPUC quoted the report as stating, "[h]ardened overhead distribution facilities performed better than non-hardened facilities."[17] However, there was no data presented in the Commission's report regarding lateral hardening.[18] The data demonstrating better performance was limited to feeder hardening and therefore not directly applicable to this program for hardening laterals.

Q. DO YOU HAVE A RECOMMENDATION FOR THE OVERHEAD LATERAL HARDENING PROGRAM?

A. Yes. I recommend reducing the budget for the Overhead Lateral Hardening program. I recommend a 10-year capital budget of roughly $12.1 million.

[15] *See* FPUC Storm Protection Plan, Appendix A, p. 44.
[16] *See* FPUC Storm Protection Plan, p. 28.
[17] *See* FPUC Storm Protection Plan, p. 28.
[18] *See* Exhibit KJM-2, State of Florida Public Service Commission, *Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018,* July 2018, p.29.

Essentially my recommendation uses the same budgets proposed by FPUC for the first 3 years (2022 to 2024) and then caps the annual spending for this program to roughly $1.5 million per year for the years 2025 to 2031. This recommended budget is shown in the following table.

Overhead Lateral Hardening

Year	FPUC 2022 SPP $millions	Recommended 2022 SPP $millions
2022	0.06	0.06
2023	0.56	0.56
2024	0.98	0.98
2025	4.41	1.5
2026	1.80	1.5
2027	2.99	1.5
2028	3.17	1.5
2029	4.71	1.5
2030	3.46	1.5
2031	2.62	1.5
Total	**24.76**	**12.1**

The basis for the reduction is two-fold. First, FPUC has failed to demonstrate that the benefits to FPUC's customers outweighs the costs for hardening overhead laterals. It is apparent from experiences in Florida that hardened poles will reduce outage costs and outage times, but the extent that this is true for this Overhead Lateral Hardening program is unknown. Second, the FPUC overall 2022-2031 SPP has a very high cost per customer and will result in excessive higher rates for ratepayers who are also experiencing high inflation pressures. Accordingly, this FPUC proposal should be scaled back.

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Q. CAN YOU DESCRIBE FPUC'S OVERHEAD LATERAL UNDERGROUNDING PROGRAM?

A. Yes. This program is intended to address undergrounding of single phase overhead electric facilities many of which are located in heavily vegetated areas, environmentally sensitive areas, or in areas where hardening the overhead facilities to NESC 250C Extreme wind standards is not practical.[19] The priority for laterals to be undergrounded is based on a Risk Resiliency Model, and specific priority will be assigned to laterals on risk ranked feeders.[20]

Q. WHAT IS THE MAGNITUDE OF THE OVERHEAD LATERAL UNDERGROUNDING PROGRAM?

A. The 10-year capital budget for the Overhead Lateral undergrounding program is $63.35 million in the 2022-2031 SPP.[21]

Q. DID FPUC PROVIDE ANY SPECIFIC VALUE FOR THE BENEFITS OF THE OVERHEAD LATERAL UNDERGROUNDING PROGRAM?

A. No. Even though this data was required in the filing by Rule 25-6.030, F.A.C., FPUC failed to provide any estimates of cost reduction or estimates of outage reduction times.[22] FPUC referenced a report prepared by the Florida PSC entitled *Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018,* dated July 2018. However, FPUC did not try to monetize the benefits

[19] *See* FPUC Storm Protection Plan, p. 28.
[20] *See* FPUC Storm Protection Plan, p. 41.
[21] *See* FPUC Storm Protection Plan, Appendix A, p. 44.
[22] *See* FPUC Storm Protection Plan, p. 29.

of undergrounding laterals, thus it is not possible to compare the benefits to the cost of the program.

Q. DO YOU HAVE A RECOMMENDATION FOR THE OVERHEAD LATERAL UNDERGROUNDING PROGRAM?

A. Yes. I recommend reducing the budget for the Overhead Lateral Undergrounding program. I recommend a 10-year capital budget of roughly $32.2 million. Essentially my recommendation uses the same budgets proposed by FPUC for the first 3 years (2022 to 2024) and then caps the annual spending for this program to roughly $4.2 million per year for the years 2025 to 2031. This recommended budget is shown in the following table.

Overhead Lateral Undergrounding

Year	FPUC 2022 SPP $millions	Recommended 2022 SPP $millions
2022	0.11	0.11
2023	1.09	1.09
2024	1.62	1.62
2025	6.23	4.2
2026	5.00	4.2
2027	8.52	4.2
2028	8.06	4.2
2029	6.44	4.2
2030	13.13	4.2
2031	13.13	4.2
Total	**63.35**	**32.22**

The basis for the reduction is two-fold. First, FPUC has failed to demonstrate the benefit to cost for overhead lateral undergrounding. It is apparent from experiences in Florida that undergrounding laterals will reduce outage costs and outage times but the extent this is true for this Overhead Lateral Undergrounding program is unknown. Second, the FPUC overall 2022-2031 SPP has a very high cost per customer and will result in excessive higher rates for ratepayers who are also experiencing high inflation pressures.

Accordingly, this FPUC proposal should be scaled back.

Q. CAN YOU DESCRIBE THE TRANSMISSION AND SUBSTATION RESILIENCY PROGRAM?

A. Yes. This program is intended to improve the electrical redundancy and resiliency to Amelia Island through the construction of an additional 138 kV transmission line, the upgrade of one of the 69kV transmission lines, and the construction of one substation.[23] This work may include upgrades to existing substations.

Q. WHAT IS THE PURPOSE OF THE NEW 138 KV TRANSMISSION LINE CONTAINED IN THE TRANSMISSION AND SUBSTATION RESILIENCY PROGRAM?

A. Amelia Island is served by a 3.56-mile long FPUC owned double circuit 138 kV transmission line. Approximately 1.1 miles is along a transmission right-of-way and the remaining 2.46 miles is along a four-lane highway. FPUC is proposing a new 138kV transmission line to provide redundancy to the existing double circuit transmission line. The proposed new transmission line will be 8.72 miles of

[23] *See* FPUC Storm Protection Plan, p. 33.

overhead transmission line and 2.03 of 138kV submarine cable.[24] The majority of the proposed route is not accessible by existing roads.[25]

Q. IS THIS NEW TRANSMISSION LINE NECESSARY FOR STORM HARDENING?

A. No. This new line is not necessary or prudent. The existing double circuit transmission line is built on concrete poles with a few lattice steel towers at the river crossing. FPUC states that the location of this transmission system makes access to it very challenging.[26] However, the existing dual circuit transmission line is adjacent to a four-lane highway providing better access than to most transmission lines in Florida and the route has limited interference with trees along the majority of the right-of-way. In addition, research by the Florida PSC found that very few non-wood poles failed during hurricanes.[27] Thus by employing the good maintenance practices as described in the FPUC 2022-2031 SPP, the existing double circuit line will be hardened against extreme wind speeds of 120 mph with Grade B strength factors.

[redacted]

[24] *See* FPUC Storm Protection Plan, p. 34.
[25] *See* FPUC's Response to OPC's First Request for Production of Documents.
[26] Direct Testimony of P. Mark Cutshaw, p. 11, line 15.
[27] *See* Exhibit KJM-2, State of Florida Public Service Commission, *Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018,* July 2018, pp.29-30.

[redacted]

Further, the proposed new 10.8 miles of new 138 kV transmission line and cable route is a very poor right-of-way which is why a submarine cable is proposed. The poles would be in low lying areas with no access roads currently in place. This line will access an alternate power source that is presently available to FPUC through JEA's transmission system and therefore adds no value under the standards of the SPP Statute and Rule.

Q. WHAT IS YOUR RECOMMENDATION FOR THIS PROJECT OF A NEW 138 KV TRANSMISSION LINE TO AMELIA ISLAND?

A. I recommend this project be excluded from the SPP because it is not a prudent investment. This recommendation is based on my review of the existing system configuration, access to the existing line, the fact that the existing line is relatively short with limited exposure and is built with 100% concrete poles and lattice steel tower specifically designed for extreme wind.

Q. WHAT IS THE PURPOSE OF THE UPGRADE OF THE 69 KV TRANSMISSION LINE AND THE UPGRADE TO AN EXISTING 69 KV

SUBSTATION CONTAINED IN THE TRANSMISSION AND SUBSTATION RESILIENCY PROGRAM?

A. Specifically, FPUC proposes to upgrade 4.45 miles of 69 kV line including reconductoring the line for increased capacity and construction of a new substation interconnection to connect to a paper mill that has generation resources that could be leveraged by FPUC during normal and emergency conditions.[28] Presently the Eight Flags Energy CHP Plant, located at the Rayonier Advanced Materials plant at Amelia Island, generates approximately 20 MW of base load power, producing enough electricity to meet 50 percent of the island's demand. The plant operates on natural gas provided by FPUC. The Rayonier Advanced Materials plant purchases the steam and heated water from the CHP plant and FPUC purchases the electricity for distribution to its retail electric customers in the area.[29] There is another paper mill on the island with a CHP plant powered by coal,[30] although based on limited scope of FPUC's filing and lack of time for discovery, it is unclear if the proposed transmission line upgrade and new substation is for one or both of these industrial sites.

Q. ARE THE UPGRADED 69KV TRANSMISSION LINE AND NEW SUBSTATION NECESSARY FOR STORM HARDENING?

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[28] *See* FPUC Storm Protection Plan p. 34.

[29] *See* Exhibit KJM-4, Fernandina Observer, *Eight Flags Energy combined heat and power plant (CHP) named best CHP project of 2016*, Suanne Thamm, December 22, 2016.

[30] *See* Exhibit KJM-5, U.S. Department of Energy Combined Heat and Power and Microgrid Installation Databases.

A. No. The 69 kV line already exists and is interconnected with an existing CHP plant. This project will increase the capacity of the line to gain access to more electricity from CHP generation. This type of power, which calls for increased investment to access an alternate power source, is not a storm hardening issue. It is a power supply hedging strategy which more appropriately belongs in a traditional rate case in which the issues of the investment in capacity compared to the access of the alternate power source can be vetted. I note that FPUC is not suggesting the paper mill will contribute aid for the increase in capacity or storm hardening of the substation. At no cost to it, the paper mill would enjoy access to a transmission grid with more capacity to sell more electricity, a more robust transmission line for the sale of electricity, and a new substation that meets FPUC storm hardening measures.

Further, there is no analysis that suggests that the CHP will be operational within 5-6 hours of a hurricane making landfall. For the CHP to aid in resiliency, it must be viable with full capacity when needed. This is outside the control of FPUC and outside the scope of the SPP Statute and Rule.

Q. WHAT IS YOUR RECOMMENDATION FOR THIS UPGRADE OF THE 69KV TRANSMISSION AND SUBSTATION AT THE PAPER MILL?

A. I recommend this project be excluded from the SPP. This project is not a storm hardening project; it is an energy delivery/energy access project. The cost of the transmission capacity increase and the new substation should have either contribution-in-aid from the CHP owner or a clear analysis showing that the investment in the new plant will be offset by the alternate energy resource. Further, the cost of this plan as a storm hardening resource has not considered the fuel cost and power purchase cost at critical times such within hours of a hurricane making landfall.

Q. WHAT IS YOUR RECOMMENDATION FOR THE TRANSMISSION AND SUBSTATION RESILIENCY PROGRAM?

A. The 10-year capital cost of this program is $86.07 million, and I recommend that two projects within the program be excluded from the SPP. The proposed 138 kV transmission line through the low-lying area around Amelia Island is not a prudent option when the existing transmission system is already hardened for extreme weather. Also, the capacity increase for interconnection of a co-generation plant needs to be analyzed from a power supply cost perspective and not based on storm hardening, especially since there are no guarantees that the plant will be operational when most needed by the FPUC.

Q. CAN YOU DESCRIBE FPUC'S FUTURE TRANSMISSION AND DISTRIBUTION ENHANCEMENTS PROGRAM?

A. Yes, this program will, at some time in the future, include some kind of distribution automation or smart grid technology which can create a self-healing system. A Supervisory Control and Data Acquisition (SCADA) system will be part of these future enhancements.[31] Because this is a future program, specific costs and details on the full deployment are not yet available.[32]

Q. DOES FPUC'S FUTURE TRANSMISSION AND DISTRIBUTION ENHANCEMENTS PROGRAM REDUCE RESTORATION COSTS?

A. No. This system does not reduce the number of outages. Instead, the system is designed to limit the outage to the smallest segment of the system. For example, if a fuse is added to a lateral and a tree falls on that lateral, the fuse opens and isolates the failed portion of the system. Only a few customers are affected by the outage, but the repair costs to remove the tree off the line and perhaps replace a pole are the same whether a fuse is on the lateral or not. The smart grid as described by FPUC is more complex but acts in a similar fashion except it uses automation to switch and isolate outages to the smallest portion of the system. Thus, there is no reduction in restoration costs for the smart grid system. In fact, FPUC failed to provide any details of the proposed system and does not include any monetized value for reduction in outage costs or reduction in outage times. Rather FPUC provides flowery language that "[t]hese systems have been proven across the nation at eliminating unnecessary outage impacts to unaffected customers ..."[33] However, FPUC has not determined what type of system they will install. If they install a SCADA system only on Amelia Island, that system will not function as a fault isolation system. Without any details about the type of system, or the actual

[31] Direct Testimony of P. Mark Cutshaw, p. 12, lines 10-14.
[32] *See* FPUC Storm Protection Plan, p. 35.
[33] *See* FPUC Storm Protection Plan, p. 36.

monetized benefits of the system, this program does not meet the requirements of the Rule 25-6.030, F.A.C.

Q. WHAT IS YOUR RECOMMENDATION REGARDING FPUC'S FUTURE TRANSMISSION AND DISTRIBUTION ENHANCEMENTS PROGRAM?

A. I recommend this program with a 10-year budget of $30 million be eliminated from FPUC's SPP because it fails to meet the two prong criteria established in Rule 25-6.030(2)(a), F.A.C. Specifically, this program, which is ill-defined but generally functions on a fault isolation system, does not reduce outage costs. The system only reduces outage times.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

BY MS. CHRISTENSEN:

Q Mr. Mara, did you have exhibits attached to your prefiled testimony labeled KJM-1 through KJM-5?

A I did.

Q And now let me note for the record, those were previously marked for identification as 47 through 51.

Do you have any corrections to those exhibits?

A No, I do not.

Q Since your summary is to be consolidated for all of the dockets, I would ask you to please provide a summary of your testimonies in Dockets 20220048, 20220049, 20220050 and 20220051, can you please provide that summary now?

A Yes, I can. Thank you for the opportunity to provide that summary.

In my testimony, I addressed -- in the testimony in all four cases, I addressed my understanding of the clear reading of the criteria needed for the storm hardening projects as defined in Rule 25-6.030, in the statute 366.96. I also provided testimony regarding the different programs and projects for each of the utilities in the different cases, including their budgets.

With regard to the statute, 366.96, my understanding is the Florida Legislature directed the

Commission to consider the estimated costs and benefits to the utility and its customers for making the improvements in the plan. Clearly, the goal is to invest in storm hardening activities that benefit customers at a cost that's reasonable for the benefits. And so in my mind, clearly, the Legislature was directing to have estimated costs and estimated benefits in order to make that comparison.

In my testimony, I also discuss the SPP. In the rule, it defined that the SPP is a group of storm protection projects to enhance the utility's infrastructure for the purpose of effectively reducing restoration costs and outage time to customers.

And then a project is defined within the rule as a project is an activity defined to enhancement of the system to reduce restoration costs and reduce outage times.

Clearly, it's a two-prong test. Both the projects and the program are required to reduce restoration costs and restoration times. So it is a two-prong test to be met.

In Section (3)(d)(1) of the Rule 25-6.030, it directs utilities to provide a description of each proposed storm protection program and how it's designed to enhance the existing system. In that description is required to include an estimate of the resulting reduction in outage time and restoration costs due to extreme weather events.

So clearly, in order to make a comparison, we have to look at both the cost and the benefits on a monetized basis. This would allow the Commission, then, to make an informed decision on the reasonableness of the plan. The need for those costs, then, are vitally important.

In reviewing the four different filings from the utilities, clearly, all four utilities provided estimates for their construction of the different programs and projects they had in place. Two of the utilities, Duke and TECO, did provide projected benefits on reduction of restoration costs, and they monetized the reduction and outage times to consumers. Florida Power & Light and FPUC did not provide that data.

In thinking about the criteria of the -- that's set forth for these storm hardening plans, or the storm protection plans, a good example of that would be the hardening of distribution poles.

Distribution poles, the utilities in the state have, for quite a number of years, changed their design and have gone to Grade B, which is a higher overload factor in increased extreme wind loading, which is not required by the National Electric Safety Code. So by increasing the strength of the poles in their design, it reduces restoration costs because the pole is less likely to fail. It also reduces outage time because the pole is less likely to fail. And this is because they've changed the design of the pole itself to be stronger.

On the other hand, if you had like for like pole replacements, or like for like replacements of infrastructure on the system, you haven't changed the strength. You haven't changed the purpose. So you haven't hardened anything. And so just replacing aging infrastructure with new infrastructure that serves the same purpose at the same strength, to me, should not be included in the SPP. The performance is going be to the same, and you are not going to get that kind of reduction.

One project that was common in two of the plans was the transmission access roads and bridges. Both Tampa Electric and Florida Power & Light had that included in their storm protection plans. And these are existing roads and rights-of-ways that have, in my opinion, served their purpose of allowing access for the utilities to do right-of-way inspection, which is included in their plans; to include inspection of the transmission lines, which are included in their plans; and to allow pole replacements of the transmission structures to harden -- harden transmission poles. In fact, Florida Power & Light has replaced well over 90 percent of their transmission poles using the existing right-of-ways.

In my opinion, the utility has a duty to maintain these access roads, and simply causing the access roads to be easier to use does not reduce outages at all, and it's a core function of the utility. In fact, TECO mentioned that the deterioration of their right-of-way was caused mostly by their vehicles using the right-of-way and the bridges. So for that reason, I don't see access roads and bridges as being an appropriate SPP project.

With FPUC, one of their major projects had to do with Amelia Island. Amelia Island is served by a transmission line, a loop transmission line, so it's a double circuit transmission line roughly three-and-a-half miles long. It's along the highway. It does cross the intercoastal waterway. There is a small section that is not along the highway but appears to have a descent right-of-way for access.

And the proposed plan is to build an alternate transmission line at a cost of $81 million, which is a third of the SPP budget. It's a longer route. It goes through the marsh, crosses the river underground, so there is two miles of transmission underground. This is a very expensive line, and very difficult to access compared to the loop line that's there right now. And so I don't believe that that particular project is a prudent project for a substation that's looped with poles that are already non-wood poles and lattice steel towers.

With regard to TECO, I recommended that the budgets for TECO to be reduced significantly. They provided a budget optimization result. That was that Figure 6.1 that was discussed earlier. And so they showed that at $1.5 billion, they were going to get benefits somewheres in the neighborhood of three-and-a-half billion. And if they went up to $2 billion, then there would be a reduction in the benefits.

Well, the same is true, if you reduce the spending, you get a reduction in benefits. Using that chart, the clear reading of that chart tells you that if you have a budget of $850 million, the benefits would drop to $3.25 million. So a 50-percent reduction in budget with only an eight-percent reduction in benefits, to me, is a pretty good deal for consumers. And so that was the basis for my recommendation on reducing the budgets for Tampa Electric. Through that, I proposed cuts in the lateral hardening, distribution lateral undergrounding and the overhead hardening programs.

With regards to Duke, Duke had a number of unique projects that weren't in any of the other utilities' plans. One was an underground flood mitigation program, where they were replacing pad-mounted equipment with pad-mounted equipment. For me, it's more of an aging infrastructure project and did not significantly impact storm hardening. So for that reason, I think that that project should be eliminated from the SPP.

They had a lattice steel tower replacement program. They identified steel towers, the lattice steel towers that they wanted to replace. You don't increase the strength of the towers loading that you put on it, the extreme wind. You are going to get the same reliability and resiliency that you had prior to doing that work. For that reason, I recommended not including that project in the SPP.

They had another project for cathodic protection for lattice steel towers. You take a transmission pole with energized conductors on it, you get corrosion because of the electrolysis on the pole in the ground, and you fix that by putting in cathodic protection. That's a standard transmission design and maintenance program. It doesn't strengthen the pole. It delays any kind of rust on the pole, but that's all it's really doing, and I don't believe that that, in fact, is a storm hardening program because it doesn't add any strength.

Another program they have was replacing the overhead guy wire. This is for a like-for-like replacement. There is nothing new or special about the overhead guy wire that they were going to put on their transmission lines. And so for that reason, I recommended excluding that from the SPP.

Thank you for your time and patience.

CHAIRMAN FAY: Great. Thank you.

MR. REHWINKEL: Mr. Chairman, would you mind if I took care of a housekeeping matter related to his amended testimony, just to clarify?

CHAIRMAN FAY: Sure.

FURTHER EXAMINATION

BY MR. REHWINKEL:

Q In your summary, Mr. Mara, you -- nothing you said about recommended disallowances for Duke Energy Florida was intended to reverse the qualifiers you made with respect to paragraph four of the 2020 -- of the

27 -- the 2021 settlement agreement, is that right?

A That is correct.

MR. REHWINKEL: Thank you.

CHAIRMAN FAY: Great. Thanks.

MS. CHRISTENSEN: We would tender the witness for cross.

CHAIRMAN FAY: Okay. Great.

FPL?

MR. WRIGHT: Thank you, Chairman. As we previously indicated at the prehearing conference, we have no cross for OPC witnesses.

CHAIRMAN FAY: Okay. Thank you.

MR. BERNIER: We also have no questions, Mr. Chairman.

CHAIRMAN FAY: Okay. TECO.

MR. MEANS: None from Tampa Electric either.

MS. KEATING: None for FPUC.

CHAIRMAN FAY: Staff?

MR. IMIG: Staff has no questions.

CHAIRMAN FAY: Okay. Commissioners?

Commissioner Graham, you are recognized.

COMMISSIONER GRAHAM: Mr. Mara, how are you doing today?

THE WITNESS: I am doing great, Commissioner. Thank you.

COMMISSIONER GRAHAM: It appears nobody else is going to ask you this question. Are you an attorney?

THE WITNESS: No, sir, I am not.

COMMISSIONER GRAHAM: Do you know who George P. Burdell is?

THE WITNESS: I have heard of him but I have never net met him.

COMMISSIONER GRAHAM: Thank you, sir.

CHAIRMAN FAY: Any other questions?

With that, there is no redirect on cross, Ms. Christensen.

MS. CHRISTENSEN: No redirect.

We would ask that Mr. Mara's exhibits for all four dockets be entered into the record.

CHAIRMAN FAY: Okay. So I have 16 through 51, essentially.

MR. REHWINKEL: Commissioner -- Mr. Chairman, while Mr. Mara was giving his summary, we had a conversation with counsel for FPL, and Exhibit 15 in the CEL, we agree with FPL that that relates solely to the winterization project testimony that was withdrawn.

CHAIRMAN FAY: Okay.

MR. REHWINKEL: So --

CHAIRMAN FAY: So we won't be entering --

MR. REHWINKEL: -- it would be appropriate not to move that one in.

CHAIRMAN FAY: Okay.

MR. WRIGHT: Chairman, I believe it's CEL Exhibit 18, which was Exhibit --

MR. REHWINKEL: Oh, I apologize. I was in the wrong, yes.

CHAIRMAN FAY: KJM-3.

MR. REHWINKEL: That's what I -- yeah.

CHAIRMAN FAY: Okay.

MR. REHWINKEL: Yes.

CHAIRMAN FAY: So with that objection, we will not enter that into the record.

MR. TRIERWEILER: And KJM, what was previously marked as KJM-5 and CEL 20 for identification, that's withdrawn?

CHAIRMAN FAY: Okay. Great.

So with those two exceptions, 16 through 51, but we will remove 18 and then what used to be KJM-5, is that correct? Okay.

(Whereupon, Exhibit Nos. 16-17, 19 & 21-51 were received into evidence.)

CHAIRMAN FAY: All right. With that, Mr. Mara, you are excused.

MS. CHRISTENSEN: Thank you.

CHAIRMAN FAY: Sure.

(Witness excused.)

CHAIRMAN FAY: Okay. Commissioners, it is 3:40. What I would like to do is give our court reporter a quick break right at that two-hour mark. We will come back at, I guess we will say we will be back at 3:50 and restart then, and probably go until somewhere around 5:30.

MR. REHWINKEL: Mr. Chairman, before we break --

CHAIRMAN FAY: Yes, Mr. Rehwinkel.

MR. REHWINKEL: -- is it your intention to hear -- we are at that point before Mr. Kollen takes the stand where we indicated we want to make an ore tenus motion for reconsideration.

CHAIRMAN FAY: Yes. That would be the time when we return before we take him up.

MR. REHWINKEL: Perfect. Thank you.

(Brief recess.)

(Transcript continues in sequence in Volume 5.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 11th day of August, 2022.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024