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: June 27, 2022

UNOPPOSED MOTION TO ACCEPT THE AMENDED DIRECT TESTIMONY OF KEVIN MARA AND LANE KOLLEN

The Citizens of the State of Florida ("Citizens"), by and through the Office of Public Counsel ("OPC"), pursuant to Rule 28-106.204, Florida Administrative Code ("F.A.C."), hereby file this Unopposed Motion to Accept the **Amended Direct Testimony of Kevin Mara and Lane Kollen** in this docket. OPC request that this Motion be granted and in support of the motion states:

1. On May 31, 2022 the OPC prefiled the Direct Testimonies of **Kevin Mara and Lane Kollen in this docket pursuant to the Order Establishing Procedure[1] ("OEP").**

2. Subsequently Duke Energy Florida ("DEF") contacted the OPC about an apparent conflict in this SPP Docket related to the Paragraph 4 of the 2021 Settlement Agreement[2] as it applies to six programs.[3] The conflict involves a commitment by the signatories (as approved by the Commission) to transfer the costs related to those six programs from base rate recovery to SPP Cost Recovery Clause ("SPPCRC") recovery. The OPC experts'

[1] Order No. PSC-2022-0119-PCO-EI, Issued March 17, 2022.
[2] Order No. PSC-2021-0202A-AS-EI, Issued June 28, 2021
[3] These six programs are listed on page 12 of Mr. Mara's testimony with the notation "Does not comply with 25-6.030."

criticisms as originally filed create doubt as to the eligibility of the costs emanating from those six programs in the SPPCRC Docket No. 20220010-EI in 2023 and in the successor docket in 2024. The OPC agreed with DEF's concerns and agreed that they needed to be allayed.

3. As a result, on June 15, 2022 DEF filed a Motion to Modify Testimony Filing Date, seeking an extension until July 1, 2022 to file rebuttal to OPC witnesses. The OPC agreed to the Motion. Therein DEF stated:

> On May 31, 2022, the Office of Public Counsel ("OPC") filed testimony of two expert witnesses. Portions of that testimony appear to be in conflict with the provisions of Paragraph 4 Paragraph 4 of the 2021 Settlement Agreement. OPC and DEF have been involved in discussions to determine the most efficient manner to handle this apparent conflict. DEF believes that an extension of the rebuttal testimony to July 1, 2022 will allow these discussions to continue in a meaningful may, such that the scope of issues to be determined by the Commission at the hearing in this docket may be reduced.

The motion was granted in Order No. PSC-2022-0226-PCO-EI, issued June 24 2022.

4. As a result of these discussions and to eliminate any and all doubt about the recoverability of these six program costs in the SPPCRC for the years 2023 and 2024, the OPC has worked with DEF to provide agreed clarification language for use in amending the testimony of the two expert witnesses engaged by the OPC to address DEF's updated SPP.

5. Accordingly, the OPC has also worked with its expert witnesses, Messrs. Mara and Kollen who were not involved in the 2021 Settlement Agreement in any way, to provide agreed-to clarifications to their testimonies that made it clear that each witness's testimony is not intended to provide a basis for disallowance of costs related to the six programs in years 2023 and 2024 while also preserving their expert opinions about the nature of the costs.

6. The agreed clarifications are intended by the OPC to communicate to the Commission that OPC is not asserting that the costs included in the six programs should be excluded from the SPP in a way that would make them ineligible for recovery in the SPPCRC in the years 2023 or 2024. To the extent it becomes necessary, the OPC is willing to stipulate to the recoverability of these costs in the SPPCRC for these years, consistent with Paragraph 4 of the 2021 Settlement Agreement.

7. Attachment 1 contains the amended testimony of Kevin Mara. The relevant amended provisions clarify that criticisms of the six programs are not offered for the purpose of exclusion from the SPP disallowance of the associated costs in the SPPCRC for the years 2023 and 2024. Included are separate, "clean" and "legislative" (informational only) versions. The clean version should be substituted for the original testimony.

8. Attachment 2 contains the amended testimony of Lane Kollen. The relevant amended provisions clarify that criticisms of the six programs are not offered for the purpose of exclusion from the SPP disallowance of the associated costs in the SPPCRC for the years 2023 and 2024. Included are separate, "clean" and "legislative" (informational only) versions. The clean version should be substituted for the original testimony.

9. The OPC asserts and DEF agrees that the amended provisions comport with Paragraph 4 of the 2021 Settlement Agreement. The OPC and DEF assert that these amended provisions will not impose a hardship on the conduct of the hearing and will in fact streamline this docket and the SPPCRC (Docket No. 20220010-EI) and facilitate the administrative efficiency of the docket and further provide good cause for accepting the amended testimonies. OPC and DEF further assert that DEF's rebuttal testimony, due July 1, will rely upon the Commission's acceptance of OPC's amended testimony. To the extent this

motion is not granted, OPC and DEF agree that DEF will have good cause to request to amend their rebuttal testimony to address the non-modified OPC testimony.

10. Counsel for PCS Phosphate, NuCor Steel, FIPUG and Walmart were contacted and stated each takes no position on the Motion.

WHEREFORE, the OPC, as not objected to by the parties to this docket, requests that the Commission accept the amended testimony of Kevin Mara and Lane Kollen in this docket and to substitute these testimonies for the testimonies filed on May 31, 2022.

Respectfully submitted,

/s/ Charles J. Rehwinkel
Charles J. Rehwinkel
Deputy Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street Room 812
Tallahassee, FL 32399-1400

Attorneys for the Citizens of the
State of Florida

CERTIFICATE OF SERVICE
Docket No. 20220050-EI

I HEREBY CERTIFY that a true and correct copy of the forgoing has been furnished by electronic mail on this 27th day of June 2022, to the following:

Robert Pickels/Matthew Bernier
Duke Energy
106 East College Avenue, Suite 800
Tallahassee FL 32301-7740
Robert.Pickels@duke-energy.com
Matthew.Bernier@duke-energy.com

Theresa Tan/Jacob Imig/Walter Trierweiler
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
Office of General Counsel
ltan@psc.state.fl.us
jimig@psc.state.fl.us
wtrierwe@psc.state.fl.us

PCS Phosphate - White Springs
James W. Brew/Laura Wynn Baker
c/o Stone Law Firm
1025 Thomas Jefferson St., NW, Eighth Floor, West Tower
Washington DC 20007
jbrew@smxblaw.com
lwb@smxblaw.com

Florida Industrial Power Users Group
Jon C. Moyle, Jr./Karen A. Putnal
c/o Moyle Law Firm
118 North Gadsden Street
Tallahassee FL 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com
mqualls@moylelaw.com

Peter J. Mattheis/Michael K. Lavanga
Joseph R. Briscar
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson Street, NW
Suite 800 West
Washington, DC 20007-5201
pjm@smxblaw.com
mkl@smxblaw.com
jrb@smxblaw.com

Walmart Inc.
Setephanie U. Eaton
c/o Spilman Law Firm
110 Oakwood Drive, Suite 500
Winston-Salem NC 27103
seaton@spilmanlaw.com

Walmart Inc. (22a PA)
Derrick Price Williamson/Steven W. Lee
c/o Spilman Law Firm
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg PA 17050
dwilliamson@spilmanlaw.com
slee@spilmanlaw.com

/s/ Charles J. Rehwinkel
Charles J. Rehwinkel
Deputy Public Counsel

Attachment 1

Amended Testimony of Kevin Mara

1. Clean Version
2. Legislative Version (Information Only)

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

Richard Gentry
Public Counsel

Charles J. Rehwinkel
Deputy Public Counsel

Anastacia Pirrello
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
(850) 488-9330

Attorneys for the Citizens
of the State of Florida

TABLE OF CONTENTS

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.

.

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.

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

Richard Gentry
Public Counsel

Charles J. Rehwinkel
Deputy Public Counsel

Anastacia Pirrello
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
(850) 488-9330

Attorneys for the Citizens
of the State of Florida

TABLE OF CONTENTS

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

Year	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

---

[27] *See* Exhibit BML-1, p. 28 of 56.

[28] ~~I do not offer an opinion about whether this SOG cost is included in base rate costs already or if it is governed by a separate settlement agreement. To the extent that there has been an established right of recovery for these SOG investments outside of base rates (which I am not conceding), then my proposal would be adjusted accordingly.~~ [Original language deleted per agreement.]

[29] *See* Exhibit BML-1, p. 32 of 56.

concrete pad with increased weight, stainless steel tie downs and to change all connections 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?

[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.

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 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

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

infrastructure replacements and therefore should be recovered in base rates. <u>I would 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.</u>

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. <u>Absent a provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI, I would</u> 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

[34] *See* Exhibit KJM-2.

that reduces storm restoration costs or customer outage times. Without a clear 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).

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

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

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

[36] *See* Exhibit KJM-2.
[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").

provision in the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-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.

.

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

[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.

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 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-

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

program which has a 10-year budget of $25 million[47] should 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 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

[47] *See* Exhibit KJM-2.
[48] *See* Exhibit BML-1 page 40 of 56.

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 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?

[49] *See* Exhibit KJM-2.

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 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

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

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 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.

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

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 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

[55] *See* Exhibit KJM-7.

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 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

[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.

made to the primary transmission feed. Thus, this program projected to spend $206 million 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

[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.

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 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

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

obsolescence with modern equipment. DEF suggests that upgrading to digital relays with 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

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

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. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

Attachment 2

Amended Testimony of Lane Kollen

1. Clean Version
2. Legislative Version (Information Only)

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

LANE KOLLEN

ON BEHALF OF THE OFFICE OF PUBLIC COUNSEL

Richard Gentry
Public Counsel

Charles J. Rehwinkel
Deputy Public Counsel

Anastacia Pirrello
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400
(850) 488-9330

Attorneys for the Citizens
of the State of Florida

TABLE OF CONTENTS

EXHIBITS

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Business Administration ("BBA") degree in accounting and a Master of Business Administration ("MBA") degree from the University of Toledo. I also earned a Master of Arts ("MA") degree in theology from Luther Rice College & Seminary. I am a Certified Public Accountant ("CPA"), with a practice license, Certified Management Accountant ("CMA"), and Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, Institute of Management Accounting, Georgia Society of CPAs, and Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than forty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on hundreds of occasions in proceedings before regulatory commissions and courts at the federal and state levels. In those proceedings, I have addressed ratemaking, accounting, finance, tax, and planning issues, among others.

I have testified before the Florida Public Service Commission on numerous occasions, including base rate, fuel adjustment clause, acquisition, and territorial proceedings involving Florida Power & Light Company ("FPL"), Duke Energy Florida ("DEF"), Talquin Electric Cooperative, City of Tallahassee, and City of Vero Beach.[1]

B. Purpose of Testimony

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY?

A. I am providing this testimony on behalf of the Florida Office of Public Counsel ("OPC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address and make recommendations regarding the proposed Storm Protection Plans ("SPP") filed by Florida Public Utilities Company ("FPUC"), Duke Energy Florida, LLC ("DEF"), Tampa Electric Company ("Tampa"), and Florida Power and Light Company ("FPL") (collectively, the "utilities"). In this testimony, I specifically address the SPP filing for DEF.

I address the scope of the proposed SPPs and the threshold economic decision criteria that the Commission should apply to the selection, ranking, and magnitude of SPP programs and projects, consistent with the statutory requirements set forth in Section 366.96, Florida Statutes, *Storm Protection Plan Cost Recovery* ("SPP Statute"), Rule 25-6.030, Florida Administrative Code ("SPP Rule"), and Rule 25-6.031, F.A.C. ("SPPCRC Rule") to the extent that the outcome of these proceedings will affect the cost recoveries in the Storm Protection Plan Cost Recovery Clause ("SPPCRC") proceedings pursuant to the SPPCRC Rule. My testimony should be considered in conjunction with the testimony of Witness Kevin Mara on behalf of OPC, subject an exception set forth in Paragraph 4 of the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI that addresses

[1] I have attached a more detailed description of my qualifications and regulatory appearances as my Exhibit LK-1.

the recovery of certain SPP costs in 2023 and 2024. I do not recommend the exclusion of such programs or costs from recovery for the years 2023 and 2024, to the extent they are subject to the exception set forth in Paragraph 4 of the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.[2]

C. Scope of The SPP Requests

Q. PLEASE SUMMARIZE THE SPP REQUESTS.

A. In the aggregate, the four utilities seek authorization for programs and projects they estimate will cost $25.323 billion over the next ten years (2023-2032), consisting of $23.167 billion in capital expenditures and $2.156 billion in operation and maintenance ("O&M") expense. The capital expenditures will have a growing and cumulative ratemaking impact for the duration of the SPPs and beyond of 40 or more years over the service lives of the plant assets. These amounts are in addition to the capital expenditures and O&M expense expended in prior years and this year for storm hardening and storm protection programs. The utilities also expect to seek authorization for additional amounts in subsequent SPP updates beyond the ten years reflected in these proceedings.

The following table provides a summary of the estimated SPP program expenditures for each utility by year and in total for the ten-year period.

[2] Specifically, my testimony wherein I recommend rejection of programs or projects or costs under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 of Mr. Mara's amended direct testimony does not apply to the costs and should not be considered where they conflict with the provisions of this order for the years 2023 and 2024.

Florida Public Utilities Company
SPP Program Expenditures
$ Millions

SPP Costs by Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Total	2.3	6.7	16.9	54.2	53.2	19.9	19.6	19.8	25.3	25.2	243.1
O&M Expense Total	1.4	1.6	1.9	3.0	2.9	1.8	1.8	1.8	1.9	1.9	20.0
Overall Total	3.7	8.3	18.7	57.2	56.1	21.8	21.4	21.6	27.2	27.1	263.1

Duke Energy Florida, LLC
SPP Program Expenditures
$ Millions

SPP Costs by Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Capital Total	602.7	693.4	775.2	748.8	747.7	749.7	748.5	750.6	749.4	751.6	7,317.5
O&M Expense Total	72.1	77.1	79.0	78.1	79.0	81.8	82.4	85.8	86.8	90.0	812.0
Overall Total	674.8	770.5	854.1	826.9	826.7	831.5	830.9	836.4	836.2	841.6	8,129.5

Tampa Electric Company
SPP Program Expenditures
$ Millions

SPP Costs by Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Total	169.9	168.7	173.1	172.9	169.0	167.5	169.6	166.0	172.5	169.4	1,698.7
O&M Expense Total	31.0	34.0	33.7	35.2	36.3	37.7	39.6	41.2	43.1	45.3	377.1
Overall Total	200.9	202.7	206.8	208.2	205.4	205.2	209.2	207.3	215.6	214.7	2,075.9

Florida Power & Light Company
SPP Program Expenditures
$ Millions

SPP Costs by Year Total Company	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Capital Total	1,458.9	1,559.5	1,520.4	1,200.8	1,319.0	1,350.0	1,388.4	1,423.4	1,347.6	1,340.1	13,908.0
O&M Expense Total	86.0	86.7	88.0	88.2	94.1	100.3	99.8	100.5	100.9	101.5	946.2
Overall Total	1,544.9	1,646.3	1,608.4	1,289.0	1,413.1	1,450.3	1,488.2	1,523.9	1,448.5	1,441.6	14,854.2

Q. WHAT EFFECTS WILL THE REQUESTS HAVE ON CUSTOMER RATES?

A. The incremental effects on present customer rates will be significant as measured over multiple ratemaking metrics, including SPP revenue requirements, net plant in service, annual electric revenues, and cost per customer. The following table provides a summary of the revenue requirements by utility and in the aggregate by year and in total for the ten-year period.

Florida Public Utilities Company
SPP Program Revenue Requirements
$ Millions

SPP Revenue Requirements By Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Total	0.3	0.6	2.0	6.0	12.5	17.0	19.0	21.0	23.2	25.7	127.3
O&M Expense Total	1.4	1.6	1.9	3.0	2.9	1.8	1.8	1.8	1.9	1.9	20.0
Overall Total	1.7	2.2	3.9	9.0	15.4	18.9	20.8	22.8	25.1	27.6	147.3

Duke Energy Florida, LLC
SPP Program Revenue Requirements
$ Millions

SPP Revenue Requirements By Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Capital Total	77.3	144.2	217.9	303.3	378.5	451.1	522.2	590.7	657.8	722.1	4,065.2
O&M Expense Total	72.1	77.1	79.0	78.1	79.0	81.8	82.4	85.8	86.8	90.0	812.0
Overall Total	149.4	221.3	296.8	381.4	457.5	533.0	604.7	676.5	744.6	812.1	4,877.2

Tampa Electric Company
SPP Program Revenue Requirements
$ Millions

SPP Revenue Requirements By Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Total	17.2	35.8	53.8	72.3	91.4	109.8	127.9	145.5	163.0	180.0	996.6
O&M Expense Total	30.7	33.6	33.4	34.9	36.0	37.4	39.3	40.9	42.8	44.9	374.0
Overall Total	47.9	69.4	87.2	107.2	127.4	147.3	167.2	186.4	205.7	224.9	1,370.7

SPP Revenue Requirements By Year Jurisdictional	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Capital Total	332.9	509.3	685.9	836.6	971.5	1,112.3	1,254.0	1,396.5	1,533.2	1,661.6	10,293.8
O&M Expense Total	85.2	85.9	87.2	87.5	93.3	99.4	98.9	99.6	100.0	100.6	937.6
Overall Total	418.0	595.2	773.2	924.1	1,064.8	1,211.7	1,352.9	1,496.1	1,633.2	1,762.2	11,231.3

Florida Power & Light Company
SPP Program Revenue Requirements
$ Millions

In addition to the revenue requirement effects of the proposed SPPs shown on the preceding tables, the following tables compare other ratemaking metrics, including capital expenditures compared to present net plant in service, increases in the revenue requirement compared to present revenues, and the cost per customer. These metrics provide additional context as to the magnitude and the impacts on customer rates.

Total 10-Year Projected Spend and Revenue Requirements
Compared to Total Net Plant in Service and Revenues
Actual Results For the 12 Months Ended December 31, 2021
$ Millions

	Net Plant In Service	10-Year Proposed Capital Spend	Percentage Increase in Net Plant	2021 Electric Revenues	Projected SPP Revenue Requirement In Year 10	Percentage Increase in Revenues
FPL	44,891.0	13,908.0	31.0%	12,244.3	1,762.2	14.4%
Duke	16,946.5	7,317.5	43.2%	5,111.8	812.1	15.9%
TEC	7,215.5	1,698.7	23.5%	2,180.0	224.9	10.3%
FPUC	94.0	243.1	258.6%	83.7	27.6	33.0%
Total	69,147.0	23,167.4	33.5%	19,619.8	2,826.8	14.4%

Total 10-Year Projected SPP Investment Per Customer Includes Capital and O&M Investment			
	Customers	Projected 10-Year Total Investment $ Millions	10-Year Investment Per Customer $
FPL	5,700,000	14,854.2	2,606
Duke	1,879,073	8,129.5	4,326
TEC	824,322	2,075.9	2,518
FPUC	32,993	263.1	7,976
Total	8,436,388	25,322.7	3,002

Q. HOW DO THESE COSTS COMPARE TO THE BENEFITS FROM POTENTIAL SAVINGS IN STORM DAMAGE AND RESTORATION COSTS?

A. The estimated costs are much greater than the benefits from potential savings for each utility and for nearly all of the programs and projects, although FPUC and FPL did not, and refused to, provide quantifications of the benefits from potential savings in storm damage and restoration costs.

The following table provides a summary of the costs and dollar benefits by utility and in the aggregate by year and in total for the ten-year period and a fifty-year period. I show $0 ("n/a") in benefits for FPUC and FPL, consistent with their failure to quantify any benefits from potential savings in storm damage and restoration costs.

	Projected 10-Year Total Investment $ Millions	Projected Annual Avoided Restoration Costs $ Millions	Escalated Avoided Restoration Costs Over 10 Years $ Millions	Benefits to Costs Ratio 10 Years %	Escalated Avoided Restoration Costs Over 50 Years $ Millions	Benefits to Costs Ratio 50 Years %
FPL	14,854.2	n/a	n/a	n/a	n/a	n/a
Duke	8,129.5	56.5	647.7	8%	6,373.0	78%
TEC	2,075.9	13.0	149.5	7%	1,470.6	71%
FPUC	263.1	n/a	n/a	n/a	n/a	n/a
Total	25,322.7	69.5	797.2		7,843.6	

Total 10-Year Projected SPP Costs and Benefits Summary
Includes Capital and O&M Investment

Note: Benefits Calculations Not Provided by FPL and FPUC.

Q. WHY ARE THESE SUMMARIES AND COMPARISONS SIGNIFICANT IN THESE PROCEEDINGS?

A. They provide context for the Commission in its review of the proposed SPPs, including the sheer magnitude of the incremental capital expenditures and O&M expense and the rate impacts of these costs, as well as for the establishment and application of threshold decision criteria for the selection, ranking, and magnitude of the SPP programs and projects that are authorized. They also demonstrate that the costs of the proposed SPP programs and projects far outweigh the benefits from savings in storm damage and restoration costs.

The Commission also should keep in mind that the impact of the SPP programs is yet another addition to the customer bill in an environment of high inflation, skyrocketing natural gas prices and other base rate increases.

D. Summary of Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Each utility's proposed SPP capital expenditures, O&M expenses, increases in rate base, and resulting increases in customer rates are significant. The SPP capital expenditures and O&M expenses are incremental costs with incremental customer rate impacts. The framework, scope, selection, ranking, magnitude, prudence, and authorization to proceed with the SPP programs and projects will be determined in these proceedings, not in the subsequent SPPCRC proceeding. Therefore, the decision criteria, ratemaking principles, and rate recovery of the SPP project costs are important factors in the decision making process in this and the other SPP proceedings now pending.

To qualify for inclusion in the SPP proceedings and cost recovery in the SPPCRC proceedings, the projects and the costs of the projects must be incremental, not simply displacements of base rate costs that would have been incurred during the normal course of business, as well as prudent, used and useful, and just and reasonable in both amount and customer impact. These factors must be considered in the decision process in the SPP proceedings, not limited to the review that will take place in the SPPCRC proceedings after the projects are selected and costs already have been incurred.

The Commission should apply rational and specific decision criteria to the selection, ranking, and magnitude of the proposed programs and projects and apply those decision criteria consistently to all four utilities in these proceedings. The decision criteria should include justification in the form of a benefit/cost analysis in addition to the qualitative assessments of whether the programs and projects will reduce restoration costs and outage times. The economic justification is an important consideration in whether the programs and projects are prudent and reasonable, a determination that can only be made in the SPP proceedings, in contrast to whether the costs actually incurred during implementation of the programs and projects were prudently incurred and reasonable, which is determined in the SPPCRC proceeding.

In addition, the total multi-year customer rate impact can be considered only in the SPP proceeding. The SPPCRC proceedings address the actual recovery and annual customer rate impact only after the decision process in these SPP proceedings is complete, projects are approved, and the SPP programs and projects are implemented.

Further, it is critical that the customer rate impact reflect only the incremental cost of the SPP projects and that all avoided cost savings be reflected as offsets to those costs either through reductions to the SPPCRC or through reductions to base rates. However, in their SPP filings, the utilities did not, with limited exceptions, explicitly exclude the costs presently recovered in base rates or expressly account for any avoided cost savings. The utilities will retain the avoided cost savings for costs presently recovered in base rates unless these costs are addressed in this proceeding and the SPPCRC proceedings or otherwise included in a negotiated resolution.

I recommend that the Commission adopt and consistently apply decision criteria for the selection, ranking, magnitude, and prudence of the SPP programs and projects for the four utilities to ensure that the utilities do not use the SPP and SPPCRC process to displace costs that are subject to and recoverable through the base rate process and shift those costs to recover them through the SPP and SPPCRC process.

I concur with Witness Mara's recommendation to exclude the costs of programs and projects that displace base rate costs that would have been incurred during the normal course of business and that are not incurred on an incremental basis specifically to achieve the objectives of the SPP Rule, except for certain costs in 2023 and 2024 that are subject to Paragraph 4 in the settlement agreement approved by the Commission in Order No.2021-0202A-AS-EI. Specifically, I do not recommend that the Commission reject programs, projects, or costs under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 of Mr. Mara's amended direct testimony that are subject to this exception. I note throughout my testimony where this exception applies.

I recommend that the Commission reject all proposed SPP projects that are not economic, meaning that they do not have a benefit-to-cost ratio of at least 100%, subject to the exception for the years 2023 and 2024 pursuant to the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI. Projects with a benefit-to-cost ratio of less than 100% are not economic, cannot be considered prudent at the point of decision in this proceeding, and cannot be considered prudent or just and reasonable for future recovery through the SPPCRC.

I recommend that the Commission adopt and consistently apply uniform methodologies among the utilities to determine the revenue requirements and rate impacts of the programs and projects in these proceedings and that it carry through those uniform methodologies to the rate calculations in the SPPCRC proceeding. More specifically, I recommend that the Commission: 1) exclude construction work in progress ("CWIP") from both the return on rate base and depreciation expense, and instead allow a deferred return on the CWIP until it is converted to plant in service or prudently abandoned, 2) allow property tax only on the net plant at the beginning of each year, 3) require a credit for the avoided depreciation expense on plant that is retired due to SPP plant investments, 4) require a realignment of the costs of pole inspections and vegetation management from base rates to the SPPCRC, and 5) require a credit for the avoided O&M expenses due to the SPP plant investments and SPP O&M expenses.

II. DECISION CRITERIA FOR THE RATIONAL SELECTION, RANKING, AND MAGNITUDE OF SPP PROGRAMS AND PROJECTS

Q. DESCRIBE THE FRAMEWORK FOR THE SELECTION AND RANKING OF SPP PROGRAMS AND PROJECTS.

A. Section 366.96, Fla. Stat., and Rule 25-6.030, F.A.C., establish the required framework for the utility's SPP, including the utility's identification of projects that are designed to reduce outage restoration costs and outage times, information necessary to develop and apply decision criteria for the selection, ranking, and magnitude of the SPP programs and costs, estimates of the customer rate impacts, and parameters for recovery of the actual costs incurred for the SPP projects offset by costs recovered through base rates and other clause recoveries as well as savings in those costs.

The SPP framework provides important customer safeguards that should be enforced to require the utility to: 1) identify new programs and projects or the expansion of existing programs and projects that are not within the scope of its existing base rate programs and cost recoveries in the normal course of business; 2) limit requests to programs and projects that are prudent and reasonable; 3) justify the selections, rankings, and magnitude of SPP programs, projects, and costs; 4) ensure there is a comparison of benefits to costs; 5) effectively consider the rate impact on customers, and 6) ensure that the utility only recovers incremental costs, net of decremental (avoided) costs or reductions in costs (savings), through the SPPCRC.

More specifically, Section 366.96(8), Fla. Stat. limits SPP programs and projects to costs not recovered through the utility's base rates. Section 366.96(8), Fla. Stat., states in part: "The annual transmission and distribution storm protection plan costs may not include costs recovered through the public utility's base rates."

Section 366.96(2)(c), Fla. Stat., limits SPP programs and projects to costs that are prudent and reasonable. The statute further defines "[t]ransmission and distribution storm protection plan costs" as "the reasonable and prudent costs to implement an approved transmission and distribution storm protection plan." Section 366.96(2)(c), Fla. Stat. Similarly, the SPPCRC Rule requires that costs included in the SPPCRC be "prudent" and "reasonable." Rule 25-6.031(3), F.A.C. Although the requirements found in the statute are repeated in the SPPCRC Rule, the determination of whether the costs included in the SPPCRC are prudent and reasonable necessarily requires that the SPP programs and projects approved in the SPP docket must be prudent to undertake and implement and that the estimated costs of the programs and projects are reasonable as a threshold matter. The sequential nature of these determinations effectively limits any subsequent assessment of prudence and reasonableness in the SPPCRC proceeding to an after-the-fact assessment of the utility's implementation of each project and the actual costs incurred.

In addition, the SPP Rule requires that the utility quantify the "benefits" and costs, compare the benefits to the costs, and provide an estimate of the revenue requirement effects for each year of the SPP. Rule 25-6.030(3)(d)4., and (3)(g), F.A.C. Section 366.96(4), Fla. Stat. requires the Commission to consider this evidence in its evaluation of the SPPs. This information allows the Commission and intervening parties to determine if the proposed projects are economic, or cost-justified, to establish thresholds, or cutoff limitations, based on whether the projects are wholly or partially self-funding through cost savings, or "benefits," and to consider these factors in establishing limitations based on the customer rate impact, not only in the first year, but over the life of the SPP itself, and then beyond the SPP, extending over the lives of the SPP project costs that were capitalized.

Further, Section 366.96, Fla. Stat., and the SPPCRC Rule limit the costs eligible for recovery through the SPPCRC to incremental costs net of avoided costs (savings). The statute and this Rule specifically require the exclusion of costs that are recovered through base rates and other clause forms of ratemaking recovery.[3]

Q. ARE THE SPP RULE AND THE SPPCRC RULE SEQUENTIAL AND INTERRELATED?

A. Yes. Certain ratemaking determinations required pursuant to the SPPCRC Rule necessarily start with an assessment of the SPP programs and projects that can only be performed in the SPP proceeding, and then are confirmed and refined in the SPPCRC proceeding for cost recovery purposes.

In the SPP proceeding, the Commission must determine the prudence of the programs upfront based on whether they are economically justified, whether the projected costs are just and reasonable, and whether the customer rate impact is reasonable. This requires the application of objective thresholds and related screening criteria to select, rank, and determine the magnitude of SPP projects. The Commission also must determine whether the Company has quantified the revenue requirement and customer rate impacts in an accurate and comprehensive manner, although the final SPPCRC rate quantifications will be performed in the SPPCRC proceeding.

[3] Section 366.96(8), Fla. Stat.; Rule 25-6.031(6)(a), F.A.C.

Q. ARE EACH OF THE UTILITIES' PROPOSED SPP PROGRAMS AND PROJECTS OUTSIDE THE SCOPE OF THE EXISTING BASE RATE PROGRAMS AND COST RECOVERIES IN THE NORMAL COURSE OF BUSINESS?

A. No. DEF and each of the other utilities have included programs and projects that are within the scope of their existing base rate programs and base rate recoveries in the normal course of business. These programs and projects are listed and addressed in greater detail by Witness Mara. These programs and projects should be excluded from the SPPs and the costs should be excluded from recovery through the SPPCRCs, subject to an exception for certain costs incurred in 2023 and 2024 addressed in Paragraph 4 of the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

The SPPs and SPPCRCs are for new and expanded programs and projects that will reduce restoration costs and outage times and for the recovery of the incremental costs of the SPP programs and projects, not to displace base rate programs and base rate recoveries. Nor are the SPPs and SPPCRCs an alternative and expedited form of rate recovery for any and all costs that arguably improve resiliency or reliability. Absent a demonstrable simultaneous, equivalent corresponding reduction of base rates, neither the Statute nor the SPP or SPPCRC Rules authorize the Commission or the utilities to displace and exclude programs and costs from base rates and then include the programs and costs in the SPPs and SPPCRCs.[4]

[4] As I noted previously in my testimony, I address the principles and costs that are included by DEF in its SPP, subject to the limited exception for certain costs addressed in Paragraph 4 of the 2021 settlement agreement approved by the Commission in Order No.2021-0202A-AS-EI.

Q. ARE EACH OF DEF'S PROPOSED PROGRAMS AND PROJECTS PRUDENT AND REASONABLE?

A. No. DEF's programs and costs are not prudent and reasonable unless they meet all of the requirements of the SPP and the SPPCRC Rules that I previously described. Certain of the utility's programs and projects fail these requirements because they are not new or expansions of existing programs outside of base rates in the normal course of business; certain programs and projects fail because they are not economic.[5]

Q. DID THE UTILITIES CONSISTENTLY APPLY A BENEFIT/COST ANALYSIS TO DETERMINE THE SELECTION, RANKING, AND MAGNITUDE OF THE SPP PROGRAMS?

A. No. The utilities used a variety of decision criteria, qualitative and quantitative, but none of them relied on a benefit/cost analysis as a threshold decision criterion to qualify a program or project for inclusion in its SPP. Nor were the decision criteria consistent among the utilities or even among each utility's SPP programs and projects.[6]

Neither FPUC nor FPL developed or relied on any benefit/cost analysis. Although neither DEF nor Tampa developed or relied on benefit/cost analyses as a threshold decision criterion to qualify their programs, they both used a form of benefit/cost analysis for the ranking and the magnitude of their programs.

However, the DEF and Tampa forms of benefit/cost analysis were flawed and used to calculate excessive dollar benefits by including the societal value of customer

[5] As I noted previously in my testimony, I address the principles and costs that are included by DEF in its SPP, subject to the limited exception for certain costs addressed in Paragraph 4 of the 2021 settlement agreement approved by the Commission in Order No.2021-0202A-AS-EI.

[6] I have attached a brief summary of each utility's decision criteria as my Exhibit LK-2.

interruptions in addition to their estimates of avoided damages and restoration costs. The societal value of customer interruptions is a highly subjective quantitative measure based on interpretations of a range of customer survey results. The societal value of customer interruptions is not a cost that actually is incurred or avoided by the utility or customer and should be excluded from the justification of SPP programs and projects using benefit cost analyses.

In addition, DEF included the avoided future cost of replacing an asset that was replaced pursuant to the SPP programs as a capital cost savings in its benefit/cost analyses. This is nothing more than legerdemain, a tactful term for the magical assertion that a capital expenditure incurred for an SPP program results in future capital expenditure savings in a base rate program. There are no savings in capital expenditures. When these fantastical savings are properly removed from DEF's benefit/cost analyses, *none* of its programs or projects are economic.[7]

Q. WHY IS AN ECONOMIC JUSTIFICATION NECESSARY AS A THRESHOLD DECISION CRITERION TO QUALIFY PROGRAMS OR PROJECTS FOR INCLUSION IN THE SPP?

A. Fundamentally, SPP programs and projects should be authorized only if the benefits exceed the costs; in other words, the benefit-to-cost ratio should be at least 100%. Neither the statute nor the SPP Rule require the Commission to approve SPP programs and projects

[7] As I noted previously in my testimony, I address the principles and costs that are included by DEF in its SPP, subject to the limited exception for certain costs addressed in Paragraph 4 of the 2021 settlement agreement approved by the Commission in Order No.2021-0202A-AS-EI.

that are uneconomic even if they meet the statutory and SPP Rule objectives to reduce restoration costs and outage times.

The programs and projects submitted within the SPP are discretionary and incremental, meaning their scope and the costs should be above and beyond the present scope and costs for actual and planned capital expenditures and O&M expenses recovered in base rates in the normal course of business. By its terms, the SPP Rule requires the utility to address and undertake projects "to enhance the utility's existing infrastructure for the purpose of reducing restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability." Rule 25-6.030(2)(a), F.A.C.

The SPP programs and projects must be incremental, including the expansions of the pole inspection and vegetation management programs and projects that were previously in effect. If the projects actually had been necessary as base rate programs in the normal course of business, but the utility failed to undertake them, then the utility would have been, and would continue to be, imprudent for its failure to construct "transmission and distribution facilities" that would withstand "extreme weather events" and its failure to undertake maintenance activities that would reduce outage durations and outage expenses. No utility and no other party has made that argument.

The economic justification standard allows the utility to propose, and the Commission to set, an appropriate and reasonable benefit-to-cost threshold, whether it is the minimum 100% that I recommend or something greater or lesser.

In addition, the economic justification allows the utility and the Commission to rank proposed programs and projects to achieve the greatest value at the lowest customer rate impact.

Further, the economic justification allows the utility and the Commission to determine the maximum amount (magnitude) of expenditures for each SPP program and project that will result in net benefits to the utility's customers.

Q. HOW SHOULD THE COMMISSION DETERMINE WHETHER THE PROPOSED SPP PROGRAMS AND PROJECTS ARE ECONOMICALLY JUSTIFIED?

A. Typically, economic justification is based on a comparison of the incremental revenues or benefits (savings) that are achieved or achievable to the incremental costs of a project, with the benefits measured as the avoided costs that will not be incurred due to the SPP programs and projects and the incremental costs as the sum of the annual revenue requirements for the SPP programs and projects. The savings in costs includes not only the avoided outage restoration costs that will not be incurred due to extreme weather events, but also the reductions in maintenance expense from the new SPP assets that require less maintenance than the base rate assets that were replaced and the future savings due to near-term accelerated and enhanced vegetation management activities and expense.

Q. DOES THE SPP RULE REQUIRE THAT THE UTILITIES PROVIDE A COMPARISON OF THE "COSTS" AND "BENEFITS" TO DETERMINE IF THE PROGRAMS AND PROJECTS ARE ECONOMICALLY JUSTIFIED?

A. Yes. The SPP Rule requires the utility to provide "[a] comparison of the costs identified in subparagraph (3)(d)3. and the benefits identified in subparagraph (3)(d)1." Rule 25-6.030(3)(d)4., F.A.C. The context and juxtaposition of the terms "costs" and "benefits" strongly imply a comparison of dollar costs and dollar benefits, not a comparison of dollar costs and qualitative benefits. The latter comparison provides no useful decision making information because it does not provide a useful threshold decision criterion to qualify programs and projects, does not provide a framework for ranking programs and projects, and does not allow a rational quantitative basis for the magnitude of programs and projects that may be included.

Q. DID EACH OF THE UTILITIES PROVIDE THE REQUIRED COMPARISON OF THE "COSTS" AND "BENEFITS" IN THEIR SPP FILINGS OR IN RESPONSE TO DISCOVERY?

A. No. FPUC and FPL provided no dollar quantifications of benefits in their SPP filings and refused to provide any dollar quantifications in response to OPC discovery. FPUC claimed that it had not quantified avoided cost savings benefits and stated that it did not rely on an economic benefit cost criterion for the selection, ranking, or magnitude of its proposed programs and projects. Both FPUC and FPL argued that the SPP Rule's text requiring the comparison of costs and benefits did not require the utilities to provide a dollar quantification of the benefits, but instead required only that there had to be benefits, which they qualitatively described to meet the "objectives" and or "requirements" of the SPP Rule.

In contrast to FPUC and FPL, DEF and Tampa quantified expected dollar benefits in their SPP filings based on their modeling results and provided additional detail on their modeling and quantifications of the dollar benefits in response to OPC discovery. DEF developed its benefit quantifications using a storm damage model developed by Guidehouse. Tampa developed its benefit quantifications using a Storm Resilience Model, which includes a Storm Impact Model, developed by 1898 & Co.

Q. ARE ANY OF UTILITIES' SPP PROGRAMS ECONOMICALLY JUSTIFIED?

A. No. This is extremely problematic. None of the SPP programs has benefits that exceed the costs. None of the utilities used a benefit/cost test to qualify its programs or projects, although DEF and Tampa used a flawed form of a benefit/cost test to rank their programs and projects and to determine the maximum expenditure levels for its programs.

Q. IF THE SPP PROGRAMS ARE NOT ECONOMICALLY JUSTIFIED, CAN THE PROGRAMS AND PROJECTS OR THE RELATED COSTS BE PRUDENT OR REASONABLE?

A. No. The statute and the SPP Rule require that the programs and the incremental cost of the programs be prudent and reasonable. If the programs and projects are not economically justified, then the costs should not be incurred; if they are not economically justified, then the programs and projects cannot be prudent and the costs would be imprudent and unreasonable.

The Commission, not the utility, is the arbiter of whether these programs and projects are prudent and reasonable. It is not enough for the utility simply to assert that the programs and projects will reduce restoration costs and outage times (without quantifying the dollar benefits from the reduction of restoration costs and outage times). This bar is a starting point as an initial screening criterion, but it is insufficient in and of itself for a determination of prudence and reasonableness.

Prudence requires that additional decision criteria be applied to determine the selection, ranking, and magnitude of the programs and projects and the costs. Specifically, an economic benefit/cost criterion is required to determine what programs, if any, are cost effective to undertake. In simple terms, it defies rational thought to undertake discretionary programs and projects and to incur the incremental costs for those programs and projects if the economic benefits are not at least equal to the costs. This is especially relevant given the current economic hardships for ratepayers.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend that the Commission adopt and consistently apply specific decision criteria for the selection, ranking, and magnitude of the utilities' SPP programs and projects for the four utilities to ensure that the utilities are not able to use the SPP and SPPCRC process to displace base rate costs that are subject to and recoverable through the base rate process and shift those costs to recover them through the SPP and SPPCRC process, subject to the exception for DEF set forth in Paragraph 4 of the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

I concur with Witness Mara's recommendation to exclude the costs of programs and projects that displace base rate costs that would have been incurred during the normal course of business and that are not incurred on an incremental basis specifically to achieve the objectives of the SPP Rule, subject to the exception for DEF set forth in Paragraph 4 of the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

I recommend that the Commission reject all proposed SPP projects that are not economic, meaning that they do not have a benefit-to-cost ratio of at least 100%. Projects with a benefit-to-cost ratio of less than 100% are not economic, cannot be considered prudent at the point of decision in this proceeding, and cannot be considered prudent or just and reasonable for future recovery through the SPPCRC, subject to the exception for DEF set forth in Paragraph 4 of the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

Alternatively, I recommend that the Commission minimize the customer rate impact (harm) of uneconomic SPP programs and projects by setting a minimum threshold benefit/cost ratio for the selection and magnitude of the SPP programs and projects, such as 70%, or limiting the rate impact over the life of the SPP to a defined threshold, such as 10% over the ten-year term of each utility's proposed SPP programs.[8] Such thresholds would result in ranking projects with greater benefits to customers and winnowing projects with lesser benefits to customers, as well as limiting the magnitude of the customer rate impact of the SPP programs and projects.

III. METHODOLOGIES TO CALCULATE THE REVENUE REQUIREMENTS AND CUSTOMER RATE IMPACTS

Q. DID THE UTILITIES CONSISTENTLY CALCULATE THE REVENUE REQUIREMENT EFFECTS OF THEIR SPP PROGRAMS?

A. No. Although each of the utilities calculated the revenue requirements as the sum of the return on rate base plus O&M expense, depreciation expense, and property tax expense, there were differences among the utilities in their calculations of rate base, depreciation expense, and property tax expense. Most significantly, there were differences in their assumptions regarding the conversions of CWIP to plant in service and the resulting calculations of depreciation expense and differences in the calculations of property tax expense.

[8] Subject to the exception set forth in Paragraph 4 of the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI,

DEF did not reflect any reductions in depreciation expense on retired plant recovered in base rates that will be replaced by SPP plant assets and recovered through the SPPCRCs. None of utilities reflected reductions in O&M expenses recovered in base rates due to savings from the SPP programs and projects. Both reductions are necessary to ensure that the utilities do not recover costs that they no longer incur as a result of the SPP programs.

If these additional savings are not considered in these SPP proceedings and accounted for in the SPPCRC proceeding or otherwise reflected in a negotiated resolution, then the utilities will retain the savings due to the reductions in expenses that presently are recovered in base rates.

Q. DID DEF'S CALCULATIONS OF THE ESTIMATED REVENUE REQUIREMENTS ALSO INCLUDE UNIQUE ERRORS THAT SHOULD BE CORRECTED IN THESE PROCEEDINGS?

A. Yes. DEF had several unique errors in its calculations of the SPP revenue requirements and customer rate impact. DEF improperly calculated depreciation expense on CWIP at the end of the prior year, but also failed to calculate depreciation expense on current year plant additions.[9] DEF improperly calculated property tax expense on the average of the net plant in service and CWIP balance in the current year instead of on the beginning

[9] DEF's response to Interrogatory No. 58 in OPC's Second Set of Interrogatories in Docket No. 20220050-EI. I have attached a copy of this response as my Exhibit LK-3. Refer also to the SPP revenue requirement calculations provided in DEF's response to POD No. 1 in OPC's First Request for Production in Docket No. 20220050-EI as an Excel attachment named "Q1 Rule 25-6030 - Rev Req & 3 yr Rate Impacts_BLM-1 Support File-POD 1."

balance of net plant in service in the current year.[10] These errors should be considered and corrected in this SPP proceeding and in the SPPCRC proceeding.

Q. DID THE UTILITIES ALL INCLUDE CWIP IN RATE BASE?

A. Yes, although there were differences in the assumptions regarding the conversions of CWIP to plant in service among the utilities. More specifically, FPUC assumed that all capital expenditures were closed to plant in service as expended in the current year. DEF assumed that CWIP was converted to plant in service throughout the current year. Tampa assumed that CWIP was converted to plant in service throughout the current year. FPL assumed that capital expenditures were closed to plant in service 50% in the current year and 50% in the following year.

Q. IS A RETURN ON CWIP IN RATE BASE EXPLICITLY AUTHORIZED IN THE STATUTE, SPP RULE, OR THE SPPCRC RULE?

A. No. Section 366.96(9), Fla. Stat. states "[i]f a capital expenditure is recoverable as a transmission and distribution storm protection plan cost, the public utility may recover the annual depreciation on the cost, calculated at the public utility's current approved depreciation rates, and a return on the undepreciated balance of the costs calculated at the public utility's weighted average cost of capital using the last approved return on equity." Similarly, the SPPCRC Rule states "[t]he utility may recover the annual depreciation expense on capitalized Storm Protection Plan expenditures using the utility's most recent Commission-approved depreciation rates. The utility may recover a return on the

[10] DEF's response to Interrogatory No. 60 in OPC's Second Set of Interrogatories in Docket No. 20220050-EI. I have attached a copy of this response as my Exhibit LK-4. Refer also to the SPP revenue requirement calculations provided in DEF's response to POD No. 1 in OPC's First Request for Production in Docket No. 20220050-EI as an Excel attachment named "Q1 Rule 25-6030 - Rev Req & 3 yr Rate Impacts_BLM-1 Support File-POD 1."

undepreciated balance of the costs calculated at the utility's weighted average cost of capital using the return on equity most recently approved by the Commission." Rule 25-6.031(6)(c), F.A.C.

The term "undepreciated balance" is not defined in the statute or the SPPCRC Rule, but typically has meaning in an accounting and ratemaking context as "net plant," defined as gross plant in service less accumulated depreciation. The term "undepreciated" typically is not applied to CWIP because CWIP is not depreciated; only plant in service is depreciated.

Q. IS IT POSSIBLE TO LEGITIMATELY ASSESS WHETHER CWIP COSTS ARE PRUDENT PRIOR TO THE COMPLETION OF CONSTRUCTION AND THE CONVERSION OF THE CWIP TO PLANT IN SERVICE?

A. No. The Commission cannot legitimately assess whether CWIP costs incurred are prudent until all costs have been incurred and converted to plant in service, whether the scope of the work actually completed was consistent with the scope included in the approved SPP programs and projects, and whether the costs actually incurred were consistent with the utility's estimated costs included in the approved SPP programs and projects.

Q. ARE THERE ALTERNATIVES TO A RETURN ON CWIP IN RATE BASE INCLUDED IN THE REVENUE REQUIREMENT AND CUSTOMER IMPACTS CONSISTENT WITH THE SUBSEQUENT CONSIDERATION OF PRUDENCE AFTER THE CWIP HAS BEEN CONVERTED TO PLANT IN SERVICE?

A. Yes. As alternatives, a return on CWIP can be deferred either as allowance for funds used during construction ("AFUDC") or as a miscellaneous deferred debit. Once construction is completed and the CWIP is converted to plant in service, then the deferred return will be added to the direct construction expenditures as plant in service in rate base and included in the depreciation expense in the SPPCRC revenue requirement.

Q. WHY IS THE RETURN ON CWIP A CONCERN THAT NEEDS TO BE ADDRESSED IN THESE PROCEEDINGS?

A. It is a concern because construction expenditures are not converted from CWIP to plant in service as they are incurred, but rather only after construction is completed. There will be no actual depreciation expense until the construction expenditures are converted from CWIP to plant in service.

The return on CWIP is also a concern because all of the utilities incur engineering costs prior to incurring actual construction expenditures on specific projects. Those costs cannot be deemed prudent or reasonable unless and until the costs are charged to specific projects, construction is completed (or prudently abandoned), and the CWIP is converted to plant in service.

Q. IS THERE A SIMILAR CONCERN WITH ANOTHER COST INCLUDED IN RATE BASE BY TAMPA THAT SHOULD BE ADDRESSED FOR ALL FOUR UTILITIES?

A. Yes. Tampa has established a separate warehouse and inventory of materials and supplies for its SPP programs and included these costs in rate base and the return on these inventories in its SPP revenue requirement and customer rate impact, which raises a concern similar to the return on CWIP. Such inventory costs should not be included in rate base or the return on these inventories in the SPP revenue requirement and customer rate impact in any utility's SPP or SPPCRC. This type of item should not be included in any company's SPP. As an alternative, a return on such inventories can be deferred either as AFUDC or as a miscellaneous deferred debit, similar to the alternatives for the return on CWIP.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes.

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

LANE KOLLEN

ON BEHALF OF THE OFFICE OF PUBLIC COUNSEL

Richard Gentry
Public Counsel

Charles J. Rehwinkel
Deputy Public Counsel

Anastacia Pirrello
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400
(850) 488-9330

Attorneys for the Citizens
of the State of Florida

TABLE OF CONTENTS

EXHIBITS

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Business Administration ("BBA") degree in accounting and a Master of Business Administration ("MBA") degree from the University of Toledo. I also earned a Master of Arts ("MA") degree in theology from Luther Rice College & Seminary. I am a Certified Public Accountant ("CPA"), with a practice license, Certified Management Accountant ("CMA"), and Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, Institute of Management Accounting, Georgia Society of CPAs, and Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than forty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on hundreds of occasions in proceedings before regulatory commissions and courts at the federal and state levels. In those proceedings, I have addressed ratemaking, accounting, finance, tax, and planning issues, among others.

I have testified before the Florida Public Service Commission on numerous occasions, including base rate, fuel adjustment clause, acquisition, and territorial proceedings involving Florida Power & Light Company ("FPL"), Duke Energy Florida ("DEF"), Talquin Electric Cooperative, City of Tallahassee, and City of Vero Beach.[1]

B. Purpose of Testimony

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY?

A. I am providing this testimony on behalf of the Florida Office of Public Counsel ("OPC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address and make recommendations regarding the proposed Storm Protection Plans ("SPP") filed by Florida Public Utilities Company ("FPUC"), Duke Energy Florida, LLC ("DEF"), Tampa Electric Company ("Tampa"), and Florida Power and Light Company ("FPL") (collectively, the "utilities"). In this testimony, I specifically address the SPP filing for DEF.

I address the scope of the proposed SPPs and the threshold economic decision criteria that the Commission should apply to the selection, ranking, and magnitude of SPP programs and projects, consistent with the statutory requirements set forth in Section 366.96, Florida Statutes, *Storm Protection Plan Cost Recovery* ("SPP Statute"), Rule 25-6.030, Florida Administrative Code ("SPP Rule"), and Rule 25-6.031, F.A.C. ("SPPCRC Rule") to the extent that the outcome of these proceedings will affect the cost recoveries in the Storm Protection Plan Cost Recovery Clause ("SPPCRC") proceedings pursuant to the SPPCRC Rule. My testimony should be considered in conjunction with the testimony of Witness Kevin Mara on behalf of OPC, subject an exception set forth in Paragraph 4 of the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI that addresses

[1] I have attached a more detailed description of my qualifications and regulatory appearances as my Exhibit LK-1.

the recovery of certain SPP costs in 2023 and 2024. I do not recommend the exclusion of such programs or costs from recovery for the years 2023 and 2024, to the extent they are subject to the exception set forth in Paragraph 4 of the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.[2]

C. Scope of The SPP Requests

Q. PLEASE SUMMARIZE THE SPP REQUESTS.

A. In the aggregate, the four utilities seek authorization for programs and projects they estimate will cost $25.323 billion over the next ten years (2023-2032), consisting of $23.167 billion in capital expenditures and $2.156 billion in operation and maintenance ("O&M") expense. The capital expenditures will have a growing and cumulative ratemaking impact for the duration of the SPPs and beyond of 40 or more years over the service lives of the plant assets. These amounts are in addition to the capital expenditures and O&M expense expended in prior years and this year for storm hardening and storm protection programs. The utilities also expect to seek authorization for additional amounts in subsequent SPP updates beyond the ten years reflected in these proceedings.

The following table provides a summary of the estimated SPP program expenditures for each utility by year and in total for the ten-year period.

[2] Specifically, my testimony wherein I recommend rejection of programs or projects or costs under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 of Mr. Mara's amended direct testimony does not apply to the costs and should not be considered where they conflict with the provisions of this order for the years 2023 and 2024.

Florida Public Utilities Company
SPP Program Expenditures
$ Millions

SPP Costs by Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Total	2.3	6.7	16.9	54.2	53.2	19.9	19.6	19.8	25.3	25.2	243.1
O&M Expense Total	1.4	1.6	1.9	3.0	2.9	1.8	1.8	1.8	1.9	1.9	20.0
Overall Total	3.7	8.3	18.7	57.2	56.1	21.8	21.4	21.6	27.2	27.1	263.1

Duke Energy Florida, LLC
SPP Program Expenditures
$ Millions

SPP Costs by Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Capital Total	602.7	693.4	775.2	748.8	747.7	749.7	748.5	750.6	749.4	751.6	7,317.5
O&M Expense Total	72.1	77.1	79.0	78.1	79.0	81.8	82.4	85.8	86.8	90.0	812.0
Overall Total	674.8	770.5	854.1	826.9	826.7	831.5	830.9	836.4	836.2	841.6	8,129.5

Tampa Electric Company
SPP Program Expenditures
$ Millions

SPP Costs by Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Total	169.9	168.7	173.1	172.9	169.0	167.5	169.6	166.0	172.5	169.4	1,698.7
O&M Expense Total	31.0	34.0	33.7	35.2	36.3	37.7	39.6	41.2	43.1	45.3	377.1
Overall Total	200.9	202.7	206.8	208.2	205.4	205.2	209.2	207.3	215.6	214.7	2,075.9

Florida Power & Light Company
SPP Program Expenditures
$ Millions

SPP Costs by Year Total Company	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Capital Total	1,458.9	1,559.5	1,520.4	1,200.8	1,319.0	1,350.0	1,388.4	1,423.4	1,347.6	1,340.1	13,908.0
O&M Expense Total	86.0	86.7	88.0	88.2	94.1	100.3	99.8	100.5	100.9	101.5	946.2
Overall Total	1,544.9	1,646.3	1,608.4	1,289.0	1,413.1	1,450.3	1,488.2	1,523.9	1,448.5	1,441.6	14,854.2

Q. WHAT EFFECTS WILL THE REQUESTS HAVE ON CUSTOMER RATES?

A. The incremental effects on present customer rates will be significant as measured over multiple ratemaking metrics, including SPP revenue requirements, net plant in service, annual electric revenues, and cost per customer. The following table provides a summary of the revenue requirements by utility and in the aggregate by year and in total for the ten-year period.

Florida Public Utilities Company
SPP Program Revenue Requirements
$ Millions

SPP Revenue Requirements By Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Total	0.3	0.6	2.0	6.0	12.5	17.0	19.0	21.0	23.2	25.7	127.3
O&M Expense Total	1.4	1.6	1.9	3.0	2.9	1.8	1.8	1.8	1.9	1.9	20.0
Overall Total	1.7	2.2	3.9	9.0	15.4	18.9	20.8	22.8	25.1	27.6	147.3

Duke Energy Florida, LLC
SPP Program Revenue Requirements
$ Millions

SPP Revenue Requirements By Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Capital Total	77.3	144.2	217.9	303.3	378.5	451.1	522.2	590.7	657.8	722.1	4,065.2
O&M Expense Total	72.1	77.1	79.0	78.1	79.0	81.8	82.4	85.8	86.8	90.0	812.0
Overall Total	149.4	221.3	296.8	381.4	457.5	533.0	604.7	676.5	744.6	812.1	4,877.2

Tampa Electric Company
SPP Program Revenue Requirements
$ Millions

SPP Revenue Requirements By Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Capital Total	17.2	35.8	53.8	72.3	91.4	109.8	127.9	145.5	163.0	180.0	996.6
O&M Expense Total	30.7	33.6	33.4	34.9	36.0	37.4	39.3	40.9	42.8	44.9	374.0
Overall Total	47.9	69.4	87.2	107.2	127.4	147.3	167.2	186.4	205.7	224.9	1,370.7

Florida Power & Light Company
SPP Program Revenue Requirements
$ Millions

SPP Revenue Requirements By Year Jurisdictional	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Capital Total	332.9	509.3	685.9	836.6	971.5	1,112.3	1,254.0	1,396.5	1,533.2	1,661.6	10,293.8
O&M Expense Total	85.2	85.9	87.2	87.5	93.3	99.4	98.9	99.6	100.0	100.6	937.6
Overall Total	418.0	595.2	773.2	924.1	1,064.8	1,211.7	1,352.9	1,496.1	1,633.2	1,762.2	11,231.3

In addition to the revenue requirement effects of the proposed SPPs shown on the preceding tables, the following tables compare other ratemaking metrics, including capital expenditures compared to present net plant in service, increases in the revenue requirement compared to present revenues, and the cost per customer. These metrics provide additional context as to the magnitude and the impacts on customer rates.

Total 10-Year Projected Spend and Revenue Requirements
Compared to Total Net Plant in Service and Revenues
Actual Results For the 12 Months Ended December 31, 2021
$ Millions

	Net Plant In Service	10-Year Proposed Capital Spend	Percentage Increase in Net Plant	2021 Electric Revenues	Projected SPP Revenue Requirement In Year 10	Percentage Increase in Revenues
FPL	44,891.0	13,908.0	31.0%	12,244.3	1,762.2	14.4%
Duke	16,946.5	7,317.5	43.2%	5,111.8	812.1	15.9%
TEC	7,215.5	1,698.7	23.5%	2,180.0	224.9	10.3%
FPUC	94.0	243.1	258.6%	83.7	27.6	33.0%
Total	69,147.0	23,167.4	33.5%	19,619.8	2,826.8	14.4%

Total 10-Year Projected SPP Investment Per Customer
Includes Capital and O&M Investment

	Customers	Projected 10-Year Total Investment $ Millions	10-Year Investment Per Customer $
FPL	5,700,000	14,854.2	2,606
Duke	1,879,073	8,129.5	4,326
TEC	824,322	2,075.9	2,518
FPUC	32,993	263.1	7,976
Total	8,436,388	25,322.7	3,002

Q. HOW DO THESE COSTS COMPARE TO THE BENEFITS FROM POTENTIAL SAVINGS IN STORM DAMAGE AND RESTORATION COSTS?

A. The estimated costs are much greater than the benefits from potential savings for each utility and for nearly all of the programs and projects, although FPUC and FPL did not, and refused to, provide quantifications of the benefits from potential savings in storm damage and restoration costs.

The following table provides a summary of the costs and dollar benefits by utility and in the aggregate by year and in total for the ten-year period and a fifty-year period. I show $0 ("n/a") in benefits for FPUC and FPL, consistent with their failure to quantify any benefits from potential savings in storm damage and restoration costs.

Total 10-Year Projected SPP Costs and Benefits Summary Includes Capital and O&M Investment						
	Projected 10-Year Total Investment $ Millions	Projected Annual Avoided Restoration Costs $ Millions	Escalated Avoided Restoration Costs Over 10 Years $ Millions	Benefits to Costs Ratio 10 Years %	Escalated Avoided Restoration Costs Over 50 Years $ Millions	Benefits to Costs Ratio 50 Years %
FPL	14,854.2	n/a	n/a	n/a	n/a	n/a
Duke	8,129.5	56.5	647.7	8%	6,373.0	78%
TEC	2,075.9	13.0	149.5	7%	1,470.6	71%
FPUC	263.1	n/a	n/a	n/a	n/a	n/a
Total	25,322.7	69.5	797.2		7,843.6	

Note: Benefits Calculations Not Provided by FPL and FPUC.

Q. WHY ARE THESE SUMMARIES AND COMPARISONS SIGNIFICANT IN THESE PROCEEDINGS?

A. They provide context for the Commission in its review of the proposed SPPs, including the sheer magnitude of the incremental capital expenditures and O&M expense and the rate impacts of these costs, as well as for the establishment and application of threshold decision criteria for the selection, ranking, and magnitude of the SPP programs and projects that are authorized. They also demonstrate that the costs of the proposed SPP programs and projects far outweigh the benefits from savings in storm damage and restoration costs.

The Commission also should keep in mind that the impact of the SPP programs is yet another addition to the customer bill in an environment of high inflation, skyrocketing natural gas prices and other base rate increases.

D. <u>Summary of Conclusions and Recommendations</u>

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Each utility's proposed SPP capital expenditures, O&M expenses, increases in rate base, and resulting increases in customer rates are significant. The SPP capital expenditures and O&M expenses are incremental costs with incremental customer rate impacts. The framework, scope, selection, ranking, magnitude, prudence, and authorization to proceed with the SPP programs and projects will be determined in these proceedings, not in the subsequent SPPCRC proceeding. Therefore, the decision criteria, ratemaking principles, and rate recovery of the SPP project costs are important factors in the decision making process in this and the other SPP proceedings now pending.

To qualify for inclusion in the SPP proceedings and cost recovery in the SPPCRC proceedings, the projects and the costs of the projects must be incremental, not simply displacements of base rate costs that would have been incurred during the normal course of business, as well as prudent, used and useful, and just and reasonable in both amount and customer impact. These factors must be considered in the decision process in the SPP proceedings, not limited to the review that will take place in the SPPCRC proceedings after the projects are selected and costs already have been incurred.

The Commission should apply rational and specific decision criteria to the selection, ranking, and magnitude of the proposed programs and projects and apply those decision criteria consistently to all four utilities in these proceedings. The decision criteria should include justification in the form of a benefit/cost analysis in addition to the qualitative assessments of whether the programs and projects will reduce restoration costs and outage times. The economic justification is an important consideration in whether the programs and projects are prudent and reasonable, a determination that can only be made in the SPP proceedings, in contrast to whether the costs actually incurred during implementation of the programs and projects were prudently incurred and reasonable, which is determined in the SPPCRC proceeding.

In addition, the total multi-year customer rate impact can be considered only in the SPP proceeding. The SPPCRC proceedings address the actual recovery and annual customer rate impact only after the decision process in these SPP proceedings is complete, projects are approved, and the SPP programs and projects are implemented.

Further, it is critical that the customer rate impact reflect only the incremental cost of the SPP projects and that all avoided cost savings be reflected as offsets to those costs either through reductions to the SPPCRC or through reductions to base rates. However, in their SPP filings, the utilities did not, with limited exceptions, explicitly exclude the costs presently recovered in base rates or expressly account for any avoided cost savings. The utilities will retain the avoided cost savings for costs presently recovered in base rates unless these costs are addressed in this proceeding and the SPPCRC proceedings or otherwise included in a negotiated resolution.

I recommend that the Commission adopt and consistently apply decision criteria for the selection, ranking, magnitude, and prudence of the SPP programs and projects for the four utilities to ensure that the utilities do not use the SPP and SPPCRC process to displace costs that are subject to and recoverable through the base rate process and shift those costs to recover them through the SPP and SPPCRC process.

I concur with Witness Mara's recommendation to exclude the costs of programs and projects that displace base rate costs that would have been incurred during the normal course of business and that are not incurred on an incremental basis specifically to achieve the objectives of the SPP Rule, except for certain costs in 2023 and 2024 that are subject to Paragraph 4 in the settlement agreement approved by the Commission in Order No.2021-0202A-AS-EI. Specifically, I do not recommend that the Commission reject programs, projects, or costs under the heading of "Does not comply with 25-6.030" as shown in the table on page 13 of Mr. Mara's amended direct testimony that are subject to this exception. I note throughout my testimony where this exception applies.

I recommend that the Commission reject all proposed SPP projects that are not economic, meaning that they do not have a benefit-to-cost ratio of at least 100%, subject to the exception for the years 2023 and 2024 pursuant to the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI. Projects with a benefit-to-cost ratio of less than 100% are not economic, cannot be considered prudent at the point of decision in this proceeding, and cannot be considered prudent or just and reasonable for future recovery through the SPPCRC.

I recommend that the Commission adopt and consistently apply uniform methodologies among the utilities to determine the revenue requirements and rate impacts of the programs and projects in these proceedings and that it carry through those uniform methodologies to the rate calculations in the SPPCRC proceeding. More specifically, I recommend that the Commission: 1) exclude construction work in progress ("CWIP") from both the return on rate base and depreciation expense, and instead allow a deferred return on the CWIP until it is converted to plant in service or prudently abandoned, 2) allow property tax only on the net plant at the beginning of each year, 3) require a credit for the avoided depreciation expense on plant that is retired due to SPP plant investments, 4) require a realignment of the costs of pole inspections and vegetation management from base rates to the SPPCRC, and 5) require a credit for the avoided O&M expenses due to the SPP plant investments and SPP O&M expenses.

II. DECISION CRITERIA FOR THE RATIONAL SELECTION, RANKING, AND MAGNITUDE OF SPP PROGRAMS AND PROJECTS

Q. DESCRIBE THE FRAMEWORK FOR THE SELECTION AND RANKING OF SPP PROGRAMS AND PROJECTS.

A. Section 366.96, Fla. Stat., and Rule 25-6.030, F.A.C., establish the required framework for the utility's SPP, including the utility's identification of projects that are designed to reduce outage restoration costs and outage times, information necessary to develop and apply decision criteria for the selection, ranking, and magnitude of the SPP programs and costs, estimates of the customer rate impacts, and parameters for recovery of the actual costs incurred for the SPP projects offset by costs recovered through base rates and other clause recoveries as well as savings in those costs.

The SPP framework provides important customer safeguards that should be enforced to require the utility to: 1) identify new programs and projects or the expansion of existing programs and projects that are not within the scope of its existing base rate programs and cost recoveries in the normal course of business; 2) limit requests to programs and projects that are prudent and reasonable; 3) justify the selections, rankings, and magnitude of SPP programs, projects, and costs; 4) ensure there is a comparison of benefits to costs; 5) effectively consider the rate impact on customers, and 6) ensure that the utility only recovers incremental costs, net of decremental (avoided) costs or reductions in costs (savings), through the SPPCRC.

More specifically, Section 366.96(8), Fla. Stat. limits SPP programs and projects to costs not recovered through the utility's base rates. Section 366.96(8), Fla. Stat., states in part: "The annual transmission and distribution storm protection plan costs may not include costs recovered through the public utility's base rates."

Section 366.96(2)(c), Fla. Stat., limits SPP programs and projects to costs that are prudent and reasonable. The statute further defines "[t]ransmission and distribution storm protection plan costs" as "the reasonable and prudent costs to implement an approved transmission and distribution storm protection plan." Section 366.96(2)(c), Fla. Stat. Similarly, the SPPCRC Rule requires that costs included in the SPPCRC be "prudent" and "reasonable." Rule 25-6.031(3), F.A.C. Although the requirements found in the statute are repeated in the SPPCRC Rule, the determination of whether the costs included in the SPPCRC are prudent and reasonable necessarily requires that the SPP programs and projects approved in the SPP docket must be prudent to undertake and implement and that the estimated costs of the programs and projects are reasonable as a threshold matter. The sequential nature of these determinations effectively limits any subsequent assessment of prudence and reasonableness in the SPPCRC proceeding to an after-the-fact assessment of the utility's implementation of each project and the actual costs incurred.

In addition, the SPP Rule requires that the utility quantify the "benefits" and costs, compare the benefits to the costs, and provide an estimate of the revenue requirement effects for each year of the SPP. Rule 25-6.030(3)(d)4., and (3)(g), F.A.C. Section 366.96(4), Fla. Stat. requires the Commission to consider this evidence in its evaluation of the SPPs. This information allows the Commission and intervening parties to determine if the proposed projects are economic, or cost-justified, to establish thresholds, or cutoff limitations, based on whether the projects are wholly or partially self-funding through cost savings, or "benefits," and to consider these factors in establishing limitations based on the customer rate impact, not only in the first year, but over the life of the SPP itself, and then beyond the SPP, extending over the lives of the SPP project costs that were capitalized.

Further, Section 366.96, Fla. Stat., and the SPPCRC Rule limit the costs eligible for recovery through the SPPCRC to incremental costs net of avoided costs (savings). The statute and this Rule specifically require the exclusion of costs that are recovered through base rates and other clause forms of ratemaking recovery.[3]

Q. ARE THE SPP RULE AND THE SPPCRC RULE SEQUENTIAL AND INTERRELATED?

A. Yes. Certain ratemaking determinations required pursuant to the SPPCRC Rule necessarily start with an assessment of the SPP programs and projects that can only be performed in the SPP proceeding, and then are confirmed and refined in the SPPCRC proceeding for cost recovery purposes.

In the SPP proceeding, the Commission must determine the prudence of the programs upfront based on whether they are economically justified, whether the projected costs are just and reasonable, and whether the customer rate impact is reasonable. This requires the application of objective thresholds and related screening criteria to select, rank, and determine the magnitude of SPP projects. The Commission also must determine whether the Company has quantified the revenue requirement and customer rate impacts in an accurate and comprehensive manner, although the final SPPCRC rate quantifications will be performed in the SPPCRC proceeding.

[3] Section 366.96(8), Fla. Stat.; Rule 25-6.031(6)(a), F.A.C.

Q. ARE EACH OF THE UTILITIES' PROPOSED SPP PROGRAMS AND PROJECTS OUTSIDE THE SCOPE OF THE EXISTING BASE RATE PROGRAMS AND COST RECOVERIES IN THE NORMAL COURSE OF BUSINESS?

A. No. DEF and each of the other utilities have included programs and projects that are within the scope of their existing base rate programs and base rate recoveries in the normal course of business. These programs and projects are listed and addressed in greater detail by Witness Mara. These programs and projects should be excluded from the SPPs and the costs should be excluded from recovery through the SPPCRCs, subject to an exception for certain costs incurred in 2023 and 2024 addressed in Paragraph 4 of the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

The SPPs and SPPCRCs are for new and expanded programs and projects that will reduce restoration costs and outage times and for the recovery of the incremental costs of the SPP programs and projects, not to displace base rate programs and base rate recoveries. Nor are the SPPs and SPPCRCs an alternative and expedited form of rate recovery for any and all costs that arguably improve resiliency or reliability. Absent a demonstrable simultaneous, equivalent corresponding reduction of base rates, neither the Statute nor the SPP or SPPCRC Rules authorize the Commission or the utilities to displace and exclude programs and costs from base rates and then include the programs and costs in the SPPs and SPPCRCs.[4]

[4] As I noted previously in my testimony, I address the principles and costs that are included by DEF in its SPP, subject to the limited exception for certain costs addressed in Paragraph 4 of the 2021 settlement agreement approved by the Commission in Order No.2021-0202A-AS-EI.

Q. ARE EACH OF DEF'S PROPOSED PROGRAMS AND PROJECTS PRUDENT AND REASONABLE?

A. No. DEF's programs and costs are not prudent and reasonable unless they meet all of the requirements of the SPP and the SPPCRC Rules that I previously described. Certain of the utility's programs and projects fail these requirements because they are not new or expansions of existing programs outside of base rates in the normal course of business; certain programs and projects fail because they are not economic.[5]

Q. DID THE UTILITIES CONSISTENTLY APPLY A BENEFIT/COST ANALYSIS TO DETERMINE THE SELECTION, RANKING, AND MAGNITUDE OF THE SPP PROGRAMS?

A. No. The utilities used a variety of decision criteria, qualitative and quantitative, but none of them relied on a benefit/cost analysis as a threshold decision criterion to qualify a program or project for inclusion in its SPP. Nor were the decision criteria consistent among the utilities or even among each utility's SPP programs and projects.[6]

Neither FPUC nor FPL developed or relied on any benefit/cost analysis. Although neither DEF nor Tampa developed or relied on benefit/cost analyses as a threshold decision criterion to qualify their programs, they both used a form of benefit/cost analysis for the ranking and the magnitude of their programs.

However, the DEF and Tampa forms of benefit/cost analysis were flawed and used to calculate excessive dollar benefits by including the societal value of customer

---

[5] As I noted previously in my testimony, I address the principles and costs that are included by DEF in its SPP, subject to the limited exception for certain costs addressed in Paragraph 4 of the 2021 settlement agreement approved by the Commission in Order No.2021-0202A-AS-EI.

[6] I have attached a brief summary of each utility's decision criteria as my Exhibit LK-2.

interruptions in addition to their estimates of avoided damages and restoration costs. The societal value of customer interruptions is a highly subjective quantitative measure based on interpretations of a range of customer survey results. The societal value of customer interruptions is not a cost that actually is incurred or avoided by the utility or customer and should be excluded from the justification of SPP programs and projects using benefit cost analyses.

In addition, DEF included the avoided future cost of replacing an asset that was replaced pursuant to the SPP programs as a capital cost savings in its benefit/cost analyses. This is nothing more than legerdemain, a tactful term for the magical assertion that a capital expenditure incurred for an SPP program results in future capital expenditure savings in a base rate program. There are no savings in capital expenditures. When these fantastical savings are properly removed from DEF's benefit/cost analyses, *none* of its programs or projects are economic.[7]

Q. WHY IS AN ECONOMIC JUSTIFICATION NECESSARY AS A THRESHOLD DECISION CRITERION TO QUALIFY PROGRAMS OR PROJECTS FOR INCLUSION IN THE SPP?

A. Fundamentally, SPP programs and projects should be authorized only if the benefits exceed the costs; in other words, the benefit-to-cost ratio should be at least 100%. Neither the statute nor the SPP Rule require the Commission to approve SPP programs and projects

[7] As I noted previously in my testimony, I address the principles and costs that are included by DEF in its SPP, subject to the limited exception for certain costs addressed in Paragraph 4 of the 2021 settlement agreement approved by the Commission in Order No.2021-0202A-AS-EI.

that are uneconomic even if they meet the statutory and SPP Rule objectives to reduce restoration costs and outage times.

The programs and projects submitted within the SPP are discretionary and incremental, meaning their scope and the costs should be above and beyond the present scope and costs for actual and planned capital expenditures and O&M expenses recovered in base rates in the normal course of business. By its terms, the SPP Rule requires the utility to address and undertake projects "to enhance the utility's existing infrastructure for the purpose of reducing restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability." Rule 25-6.030(2)(a), F.A.C.

The SPP programs and projects must be incremental, including the expansions of the pole inspection and vegetation management programs and projects that were previously in effect. If the projects actually had been necessary as base rate programs in the normal course of business, but the utility failed to undertake them, then the utility would have been, and would continue to be, imprudent for its failure to construct "transmission and distribution facilities" that would withstand "extreme weather events" and its failure to undertake maintenance activities that would reduce outage durations and outage expenses. No utility and no other party has made that argument.

The economic justification standard allows the utility to propose, and the Commission to set, an appropriate and reasonable benefit-to-cost threshold, whether it is the minimum 100% that I recommend or something greater or lesser.

In addition, the economic justification allows the utility and the Commission to rank proposed programs and projects to achieve the greatest value at the lowest customer rate impact.

Further, the economic justification allows the utility and the Commission to determine the maximum amount (magnitude) of expenditures for each SPP program and project that will result in net benefits to the utility's customers.

Q. HOW SHOULD THE COMMISSION DETERMINE WHETHER THE PROPOSED SPP PROGRAMS AND PROJECTS ARE ECONOMICALLY JUSTIFIED?

A. Typically, economic justification is based on a comparison of the incremental revenues or benefits (savings) that are achieved or achievable to the incremental costs of a project, with the benefits measured as the avoided costs that will not be incurred due to the SPP programs and projects and the incremental costs as the sum of the annual revenue requirements for the SPP programs and projects. The savings in costs includes not only the avoided outage restoration costs that will not be incurred due to extreme weather events, but also the reductions in maintenance expense from the new SPP assets that require less maintenance than the base rate assets that were replaced and the future savings due to near-term accelerated and enhanced vegetation management activities and expense.

Q. DOES THE SPP RULE REQUIRE THAT THE UTILITIES PROVIDE A COMPARISON OF THE "COSTS" AND "BENEFITS" TO DETERMINE IF THE PROGRAMS AND PROJECTS ARE ECONOMICALLY JUSTIFIED?

A. Yes. The SPP Rule requires the utility to provide "[a] comparison of the costs identified in subparagraph (3)(d)3. and the benefits identified in subparagraph (3)(d)1." Rule 25-6.030(3)(d)4., F.A.C. The context and juxtaposition of the terms "costs" and "benefits" strongly imply a comparison of dollar costs and dollar benefits, not a comparison of dollar costs and qualitative benefits. The latter comparison provides no useful decision making information because it does not provide a useful threshold decision criterion to qualify programs and projects, does not provide a framework for ranking programs and projects, and does not allow a rational quantitative basis for the magnitude of programs and projects that may be included.

Q. DID EACH OF THE UTILITIES PROVIDE THE REQUIRED COMPARISON OF THE "COSTS" AND "BENEFITS" IN THEIR SPP FILINGS OR IN RESPONSE TO DISCOVERY?

A. No. FPUC and FPL provided no dollar quantifications of benefits in their SPP filings and refused to provide any dollar quantifications in response to OPC discovery. FPUC claimed that it had not quantified avoided cost savings benefits and stated that it did not rely on an economic benefit cost criterion for the selection, ranking, or magnitude of its proposed programs and projects. Both FPUC and FPL argued that the SPP Rule's text requiring the comparison of costs and benefits did not require the utilities to provide a dollar quantification of the benefits, but instead required only that there had to be benefits, which they qualitatively described to meet the "objectives" and or "requirements" of the SPP Rule.

In contrast to FPUC and FPL, DEF and Tampa quantified expected dollar benefits in their SPP filings based on their modeling results and provided additional detail on their modeling and quantifications of the dollar benefits in response to OPC discovery. DEF developed its benefit quantifications using a storm damage model developed by Guidehouse. Tampa developed its benefit quantifications using a Storm Resilience Model, which includes a Storm Impact Model, developed by 1898 & Co.

Q. ARE ANY OF UTILITIES' SPP PROGRAMS ECONOMICALLY JUSTIFIED?

A. No. This is extremely problematic. None of the SPP programs has benefits that exceed the costs. None of the utilities used a benefit/cost test to qualify its programs or projects, although DEF and Tampa used a flawed form of a benefit/cost test to rank their programs and projects and to determine the maximum expenditure levels for its programs.

Q. IF THE SPP PROGRAMS ARE NOT ECONOMICALLY JUSTIFIED, CAN THE PROGRAMS AND PROJECTS OR THE RELATED COSTS BE PRUDENT OR REASONABLE?

A. No. The statute and the SPP Rule require that the programs and the incremental cost of the programs be prudent and reasonable. If the programs and projects are not economically justified, then the costs should not be incurred; if they are not economically justified, then the programs and projects cannot be prudent and the costs would be imprudent and unreasonable.

The Commission, not the utility, is the arbiter of whether these programs and projects are prudent and reasonable. It is not enough for the utility simply to assert that the programs and projects will reduce restoration costs and outage times (without quantifying the dollar benefits from the reduction of restoration costs and outage times). This bar is a starting point as an initial screening criterion, but it is insufficient in and of itself for a determination of prudence and reasonableness.

Prudence requires that additional decision criteria be applied to determine the selection, ranking, and magnitude of the programs and projects and the costs. Specifically, an economic benefit/cost criterion is required to determine what programs, if any, are cost effective to undertake. In simple terms, it defies rational thought to undertake discretionary programs and projects and to incur the incremental costs for those programs and projects if the economic benefits are not at least equal to the costs. This is especially relevant given the current economic hardships for ratepayers.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend that the Commission adopt and consistently apply specific decision criteria for the selection, ranking, and magnitude of the utilities' SPP programs and projects for the four utilities to ensure that the utilities are not able to use the SPP and SPPCRC process to displace base rate costs that are subject to and recoverable through the base rate process and shift those costs to recover them through the SPP and SPPCRC process, subject to the exception for DEF set forth in ~~Subject to~~ Paragraph 4 of the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI~~,~~.

I concur with Witness Mara's recommendation to exclude the costs of programs and projects that displace base rate costs that would have been incurred during the normal course of business and that are not incurred on an incremental basis specifically to achieve the objectives of the SPP Rule, subject to the exception for DEF set forth in Paragraph 4 of the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.~~.~~[8]

I recommend that the Commission reject all proposed SPP projects that are not economic, meaning that they do not have a benefit-to-cost ratio of at least 100%. Projects with a benefit-to-cost ratio of less than 100% are not economic, cannot be considered prudent at the point of decision in this proceeding, and cannot be considered prudent or just and reasonable for future recovery through the SPPCRC, subject to the exception for

DEF set forth in Paragraph 4 of the 2021 Settlement agreement approved in Order No. PSC-2021-0202A-AS-EI.

Alternatively, I recommend that the Commission minimize the customer rate impact (harm) of uneconomic SPP programs and projects by setting a minimum threshold benefit/cost ratio for the selection and magnitude of the SPP programs and projects, such as 70%, or limiting the rate impact over the life of the SPP to a defined threshold, such as 10% over the ten-year term of each utility's proposed SPP programs.[9] Such thresholds would result in ranking projects with greater benefits to customers and winnowing projects with lesser benefits to customers, as well as limiting the magnitude of the customer rate impact of the SPP programs and projects.

III. METHODOLOGIES TO CALCULATE THE REVENUE REQUIREMENTS AND CUSTOMER RATE IMPACTS

Q. DID THE UTILITIES CONSISTENTLY CALCULATE THE REVENUE REQUIREMENT EFFECTS OF THEIR SPP PROGRAMS?

A. No. Although each of the utilities calculated the revenue requirements as the sum of the return on rate base plus O&M expense, depreciation expense, and property tax expense, there were differences among the utilities in their calculations of rate base, depreciation expense, and property tax expense. Most significantly, there were differences in their assumptions regarding the conversions of CWIP to plant in service and the resulting

[9] Subject to the exception set forth in Paragraph 4 of the 2021 settlement agreement approved in Order No. PSC-2021-0202A-AS-EI,

calculations of depreciation expense and differences in the calculations of property tax expense.

DEF did not reflect any reductions in depreciation expense on retired plant recovered in base rates that will be replaced by SPP plant assets and recovered through the SPPCRCs. None of utilities reflected reductions in O&M expenses recovered in base rates due to savings from the SPP programs and projects. Both reductions are necessary to ensure that the utilities do not recover costs that they no longer incur as a result of the SPP programs.

If these additional savings are not considered in these SPP proceedings and accounted for in the SPPCRC proceeding or otherwise reflected in a negotiated resolution, then the utilities will retain the savings due to the reductions in expenses that presently are recovered in base rates.

Q. DID DEF'S CALCULATIONS OF THE ESTIMATED REVENUE REQUIREMENTS ALSO INCLUDE UNIQUE ERRORS THAT SHOULD BE CORRECTED IN THESE PROCEEDINGS?

A. Yes. DEF had several unique errors in its calculations of the SPP revenue requirements and customer rate impact. DEF improperly calculated depreciation expense on CWIP at the end of the prior year, but also failed to calculate depreciation expense on current year plant additions.[10] DEF improperly calculated property tax expense on the average of the net plant in service and CWIP balance in the current year instead of on the beginning

[10] DEF's response to Interrogatory No. 58 in OPC's Second Set of Interrogatories in Docket No. 20220050-EI. I have attached a copy of this response as my Exhibit LK-3. Refer also to the SPP revenue requirement calculations provided in DEF's response to POD No. 1 in OPC's First Request for Production in Docket No. 20220050-EI as an Excel attachment named "Q1 Rule 25-6030 - Rev Req & 3 yr Rate Impacts_BLM-1 Support File-POD 1."

balance of net plant in service in the current year.[11] These errors should be considered and corrected in this SPP proceeding and in the SPPCRC proceeding.

Q. DID THE UTILITIES ALL INCLUDE CWIP IN RATE BASE?

A. Yes, although there were differences in the assumptions regarding the conversions of CWIP to plant in service among the utilities. More specifically, FPUC assumed that all capital expenditures were closed to plant in service as expended in the current year. DEF assumed that CWIP was converted to plant in service throughout the current year. Tampa assumed that CWIP was converted to plant in service throughout the current year. FPL assumed that capital expenditures were closed to plant in service 50% in the current year and 50% in the following year.

Q. IS A RETURN ON CWIP IN RATE BASE EXPLICITLY AUTHORIZED IN THE STATUTE, SPP RULE, OR THE SPPCRC RULE?

A. No. Section 366.96(9), Fla. Stat. states "[i]f a capital expenditure is recoverable as a transmission and distribution storm protection plan cost, the public utility may recover the annual depreciation on the cost, calculated at the public utility's current approved depreciation rates, and a return on the undepreciated balance of the costs calculated at the public utility's weighted average cost of capital using the last approved return on equity." Similarly, the SPPCRC Rule states "[t]he utility may recover the annual depreciation expense on capitalized Storm Protection Plan expenditures using the utility's most recent Commission-approved depreciation rates. The utility may recover a return on the

[11] DEF's response to Interrogatory No. 60 in OPC's Second Set of Interrogatories in Docket No. 20220050-EI. I have attached a copy of this response as my Exhibit LK-4. Refer also to the SPP revenue requirement calculations provided in DEF's response to POD No. 1 in OPC's First Request for Production in Docket No. 20220050-EI as an Excel attachment named "Q1 Rule 25-6030 - Rev Req & 3 yr Rate Impacts_BLM-1 Support File-POD 1."

undepreciated balance of the costs calculated at the utility's weighted average cost of capital using the return on equity most recently approved by the Commission." Rule 25-6.031(6)(c), F.A.C.

The term "undepreciated balance" is not defined in the statute or the SPPCRC Rule, but typically has meaning in an accounting and ratemaking context as "net plant," defined as gross plant in service less accumulated depreciation. The term "undepreciated" typically is not applied to CWIP because CWIP is not depreciated; only plant in service is depreciated.

Q. IS IT POSSIBLE TO LEGITIMATELY ASSESS WHETHER CWIP COSTS ARE PRUDENT PRIOR TO THE COMPLETION OF CONSTRUCTION AND THE CONVERSION OF THE CWIP TO PLANT IN SERVICE?

A. No. The Commission cannot legitimately assess whether CWIP costs incurred are prudent until all costs have been incurred and converted to plant in service, whether the scope of the work actually completed was consistent with the scope included in the approved SPP programs and projects, and whether the costs actually incurred were consistent with the utility's estimated costs included in the approved SPP programs and projects.

Q. ARE THERE ALTERNATIVES TO A RETURN ON CWIP IN RATE BASE INCLUDED IN THE REVENUE REQUIREMENT AND CUSTOMER IMPACTS CONSISTENT WITH THE SUBSEQUENT CONSIDERATION OF PRUDENCE AFTER THE CWIP HAS BEEN CONVERTED TO PLANT IN SERVICE?

A. Yes. As alternatives, a return on CWIP can be deferred either as allowance for funds used during construction ("AFUDC") or as a miscellaneous deferred debit. Once construction is completed and the CWIP is converted to plant in service, then the deferred return will be added to the direct construction expenditures as plant in service in rate base and included in the depreciation expense in the SPPCRC revenue requirement.

Q. WHY IS THE RETURN ON CWIP A CONCERN THAT NEEDS TO BE ADDRESSED IN THESE PROCEEDINGS?

A. It is a concern because construction expenditures are not converted from CWIP to plant in service as they are incurred, but rather only after construction is completed. There will be no actual depreciation expense until the construction expenditures are converted from CWIP to plant in service.

The return on CWIP is also a concern because all of the utilities incur engineering costs prior to incurring actual construction expenditures on specific projects. Those costs cannot be deemed prudent or reasonable unless and until the costs are charged to specific projects, construction is completed (or prudently abandoned), and the CWIP is converted to plant in service.

Q. IS THERE A SIMILAR CONCERN WITH ANOTHER COST INCLUDED IN RATE BASE BY TAMPA THAT SHOULD BE ADDRESSED FOR ALL FOUR UTILITIES?

A. Yes. Tampa has established a separate warehouse and inventory of materials and supplies for its SPP programs and included these costs in rate base and the return on these inventories in its SPP revenue requirement and customer rate impact, which raises a concern similar to the return on CWIP. Such inventory costs should not be included in rate base or the return on these inventories in the SPP revenue requirement and customer rate impact in any utility's SPP or SPPCRC. This type of item should not be included in any company's SPP. As an alternative, a return on such inventories can be deferred either as AFUDC or as a miscellaneous deferred debit, similar to the alternatives for the return on CWIP.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes.