BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20200067-EI

Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.
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DOCKET NO. 20200069-EI

Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.
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DOCKET NO. 20200070-EI

Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Gulf Power Company.
_______________________________/

DOCKET NO. 20200071-EI

Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.
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DOCKET NO. 20200092-EI

Storm Protection Plan Cost Recovery Clause.
_______________________________/

VOLUME 2

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN GARY F. CLARK
COMMISSIONER ART GRAHAM
COMMISSIONER JULIE I. BROWN
COMMISSIONER DONALD J. POLMANN
COMMISSIONER ANDREW GILES FAY

DATE: Monday, August 10, 2020

TIME: Commenced: 1:00 p.m.
Concluded: 2:15 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
114 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

WITNESSES

I N D E X (CONTINUED)

WITNESSES

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

(Whereupon, prefiled direct testimony of Michael Jarro was inserted.)

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael Jarro. My business address is Florida Power & Light Company, 15430 Endeavor Drive, Jupiter, FL, 33478.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as the Vice President of Distribution Operations.

Q. Please describe your duties and responsibilities in that position.

A. My current responsibilities include the operation and maintenance of FPL's approximately 68,000 miles of distribution infrastructure, including 42,000 miles of overhead and 26,000 miles of underground, that safely, reliably, and efficiently deliver electricity to more than five million customers in FPL's service territory covering approximately 28,000 square miles. I am responsible for the oversight of more than 1,600 employees in a control center and sixteen management areas. The functions and operations within my area are quite diverse and include distribution operations, major projects and construction services, power quality, meteorology, and other operations that together help provide the highest level of service to FPL's customers.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Miami with a Bachelor of Science Degree in Mechanical Engineering and Florida International University with a Master of Business Administration. I joined FPL in 1997 and have held several leadership positions in distribution operations and customer service, including serving as distribution reliability manager, manager of distribution operations for south Miami-Dade area, control center general manager, director of network operations, senior director of customer strategy and analytics, senior director of power delivery central maintenance and construction, and vice-president of transmission and substations.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present and provide an overview of FPL's proposed 2020-2029 Storm Protection Plan ("SPP" or "the Plan"), which is attached to my direct testimony as Exhibit MJ-1, and demonstrate that FPL's SPP is in compliance with Section 366.96, Florida Statutes ("F.S.") and Rule 25-6.030, Florida Administrative Code ("F.A.C."). I will provide a description of each storm protection program included in FPL's SPP and how it is expected to reduce restoration costs and outage times. I will also describe the estimated start/completion dates, estimated costs, and criteria used to select and prioritize the projects in each program. Finally, I will describe the additional detail provided for the first three years of FPL's SPP pursuant to Rule 25-6.030(3)(e)-(f), (h), and (i), F.A.C.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit MJ-1 – FPL's Storm Protection Plan 2020-2029.

II. <u>OVERVIEW OF FPL'S SPP</u>

Q. What is the purpose of FPL's SPP?

A. On June 27, 2019, the Governor of Florida signed into law the Storm Protection Plan Cost Recovery legislation, which was codified in Section 366.96, F.S. As part of the new law, the Florida Legislature expressly found that it is in the State's interest: (a) "to strengthen electric utility infrastructure to withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management;" and (b) "for each electric utility to mitigate restoration costs and outage times to utility customers when developing transmission and distribution storm protection plans." *See* Sections 366.96(1)(c)-(d), F.S. Based on these findings, the Florida Legislature directed each electric utility to file a SPP with the Florida Public Service Commission ("Commission") covering the immediate ten (10) year planning period. *See* Section 366.96(3), F.S. Consistent with this legislative requirement, FPL is submitting its SPP for the ten-year period of 2020-2029.

FPL's SPP is a systematic approach to achieve the legislative objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. As required by Rule 25-6.030, F.A.C., FPL's SPP includes, among other things, a description of each proposed storm protection program, including: (a) how each program will enhance the existing system to reduce restoration costs and outage times; (b) applicable start and completion dates for each program; (c) a cost estimate for each program; (d) a comparison of the costs and benefits for each program; and (e) a description of how each program is prioritized. The SPP also provides an estimate of the annual jurisdictional revenue requirement for each year of the SPP and additional details on each program for the first three years of the SPP (2020-2022), including estimated rate impacts.

Q. What programs are included in FPL's SPP?

A. FPL's SPP is, in large part, a continuation and expansion of its previously approved storm hardening and storm preparedness programs, and includes the following SPP programs:

- Pole Inspections – Distribution Program
- Structures/Other Equipment Inspections – Transmission Program
- Feeder Hardening – Distribution Program
- Lateral Hardening (Undergrounding) – Distribution Program
- Wood Structures Hardening (Replacing) – Transmission Program
- Vegetation Management – Distribution Program
- Vegetation Management – Transmission Program

In addition, FPL proposes to implement a new Substation Storm Surge/Flood Mitigation Program to protect T&D substations and equipment that are susceptible to storm surge or flooding during extreme weather events.

With the exception of the new storm surge/flood mitigation program, the majority of these programs have been in place since 2007. As demonstrated by recent storm events, these programs have been successful in reducing restoration costs and outage times following major storms, as well as improving day-to-day reliability. FPL submits that continuing these previously approved storm hardening and storm preparedness programs in the SPP, together with the new storm surge/flood mitigation program, is appropriate and necessary to meet the requirements of Section 366.96, F.S., and Rule 25-6.030, F.A.C. These programs will address the expectations of FPL's customers and other stakeholders for increased storm resiliency, and will result in fewer outages, reduced restoration costs, and prompt service restoration. The SPP will continue and expand the benefits of hardening, including improved day-to-day reliability, to all customers throughout FPL's system.

Q. Please provide an overview of the benefits of FPL's SPP.

A. The major benefit of FPL's SPP is to provide increased resiliency and faster restoration to the electric infrastructure that FPL's five million customers and Florida's economy rely on for their electricity needs. Safe and reliable electric service is essential to the life, health, and safety of the public, and has become a critical component of modern life. Florida remains the most hurricane-prone state in the nation and, with the significant coast-line exposure of FPL's system and the fact that the vast majority of FPL's customers live within 20 miles of the coast, a robust storm protection plan is critical to maintaining and improving grid resiliency and storm restoration as contemplated by the Legislature in Section 366.96.

FPL's SPP programs have already demonstrated that they have provided and will continue to provide increased Transmission and Distribution ("T&D") infrastructure resiliency, reduced restoration time, and reduced restoration cost when FPL is impacted by extreme weather events. FPL performed an analysis of Hurricanes Matthew and Irma that indicated the restoration construction man-hours ("CMH"), days to restore, and storm restoration costs for these storms would have been significantly greater without FPL's storm hardening programs. In the case of Hurricane Matthew, FPL estimated that without hardening, restoration would have taken two additional days (50% longer), and resulted in additional restoration costs of $105 million (36% higher than actual costs). In the case of Hurricane Irma, FPL estimated that without hardening, restoration would have taken four additional days (40% longer), and resulted in additional restoration costs of $496 million (40% higher than actual costs). A copy of FPL's analysis is provided in Appendix A to Exhibit MJ-1.

A detailed summary of the benefits of FPL's SPP is provided in Section II of the SPP, and the benefits of each program are provided in Section IV of the SPP.

Q. Does FPL's SPP address recovery of the costs associated with the SPP?

A. No. FPL anticipates the programs included in the SPP will have zero bill impacts on customer bills during the first year of the SPP and only minimal bill increases for years two and three of the SPP. However, the recovery of the actual costs associated with the SPP, as well as the costs to be included in FPL's Storm Protection Plan Cost Recovery Clause, will be addressed in subsequent and separate Storm Protection Plan Cost Recovery Clause dockets pursuant to Rule 25-6.031, F.A.C. The Commission has opened Docket No. 20200092-EI to address Storm Protection Plan Cost Recovery Clause petitions to be filed the third quarter of 2020.

III. DESCRIPTION OF EACH SPP PROGRAM

Q. Has FPL provided the information required by Rule 25-6.030(3)(d) for each program included in its SPP?

A. Yes. FPL's SPP provides the information required by the Rule 25-6.030(3)(d) for each program. If applicable, each program description included in FPL's SPP includes: (1) a description of how each program is designed to enhance FPL's existing transmission and distribution facilities including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions; (2) identification of the actual or estimated start and completion dates of the program; (3) a cost estimate including capital and operating expenses; (4) a comparison of the costs and the benefits; and (5) a description of the criteria used to select and prioritize proposed storm protection programs. Each of the above listed descriptions is provided in Section IV of FPL's SPP. Below, I will provide a brief overview of each program included in FPL's SPP.

Q. Please provide a summary of FPL's Pole Inspection – Distribution Program included in the SPP.

A. The Pole Inspection – Distribution Program included in the SPP is a continuation of FPL's existing Commission-approved distribution pole inspection program. FPL's existing, Commission-approved distribution pole inspection program is an eight-year pole inspection cycle for all distribution poles that targets approximately 1/8 of the system annually (the actual number of poles inspected can vary somewhat from year to year). To ensure inspection coverage throughout its service territory, FPL established nine inspection zones (based on FPL's management areas and pole population) and annually performs pole inspections of approximately 1/8 of the distribution poles in each of these zones, as well as any necessary remediation as a result of such inspections. As explained in the SPP, recent storm events demonstrate that FPL's existing distribution pole inspection program has contributed to the overall improvement in distribution pole performance during storms, resulting in reductions in storm damage to poles, days to restore, and storm restoration costs.

With approximately 1.2 million distribution poles as of year-end 2019, FPL expects to inspect approximately 150,000 poles annually (spread throughout its nine inspection zones) during the 2020-2029 SPP period. The total estimated costs for the Pole Inspection – Distribution Program for the ten-year period of 2020-2029 is $605 million with an annual average cost of approximately $61 million, which is consistent with historical costs for the existing distribution pole inspection program.[1] A detailed description of the Pole Inspection – Distribution Program is provided in Section IV(A) of FPL's SPP.

Q. Please provide a summary of FPL's Structures/Other Equipment Inspections – Transmission Program included in the SPP.

A. The Structures/Other Equipment Inspections – Transmission Program included in the SPP is a continuation of FPL's existing Commission-approved transmission inspection program. The SPP will continue FPL's current, Commission-approved transmission inspection program which requires: (a) transmission circuits and substations and all associated hardware to be inspected on a six-year cycle; (b) wood structures to be inspected visually from the ground on an annual basis and climbing or bucket truck inspections to be conducted on a six-year cycle; and (c) steel and concrete structures to be inspected visually on an annual basis and climbing or bucket truck inspections to be conducted on a ten-year cycle. As explained in the SPP, the performance of FPL's transmission facilities during recent storm events indicates FPL's transmission inspection program has contributed to the overall storm resiliency of the transmission system and provided savings in storm restoration costs.

FPL expects to inspect approximately 68,000 structures annually during the 2020-2029 SPP period. The total estimated costs for the Structures/Other Equipment Inspections – Transmission Program for the ten-year period of 2020-2029 is $500 million with an annual average cost of approximately $50 million, which is consistent with historical costs for the

[1] Note, the 2020-2029 program costs shown above are projected costs estimated as of the time of this filing. Subsequent projected and actual costs could vary by as much as 10% to 15%. The annual projected costs, actual/estimated costs, actuals costs, and true-up of actual costs to be included in FPL's Storm Protection Plan Cost Recovery Clause will all be addressed in subsequent and separate Storm Protection Plan Cost Recovery Clause filings pursuant to Rule 25-6.031, F.A.C. The Commission has opened Docket No. 20200092-EI to address Storm Protection Plan Cost Recovery Clause petitions to be filed the third quarter of 2020.

existing transmission inspection program.[2] A detailed description of the Structures/Other Equipment Inspections – Transmission Program is provided in Section IV(B) of FPL's SPP.

Q. Please provide a summary of FPL's Feeder Hardening (EWL) - Distribution Program included in the SPP.

A. The Feeder Hardening (EWL) – Distribution Program included in the SPP is a continuation of FPL's existing Commission-approved approach to harden existing feeders and certain critical distribution poles, as well as FPL's initiative to design and construct new pole lines and major planned work to meet the National Electrical Safety Code's ("NESC") extreme wind loading criteria ("EWL"). During the period 2006-2019, FPL hardened over 1,300 existing feeders, the vast majority being Critical Infrastructure Function ("CIF") feeders (*i.e.*, feeders that serve hospitals, 911 centers, police and fire stations, water treatment facilities, county emergency operation centers) and Community Project feeders (*i.e.*, feeders that serve other key community needs like gas stations, grocery stores and pharmacies) throughout FPL's service territory. Additional feeders were hardened as a result of FPL's Priority Feeder Initiative, a reliability program that targeted feeders experiencing the highest number of interruptions and/or customers interrupted. FPL also applied EWL to the design and construction of new pole lines and major planned work, including pole line extensions and relocations and certain pole replacements.

As provided in previous FPL Annual Reliability Report filings and three-year Storm Hardening Plan filings (per Rule 25-6.0342, F.A.C.), hardened feeders perform better than non-hardened feeders, both in day-to-day reliability performance and during severe storms. Additionally, upon review of the electric utilities' storm hardening and storm preparedness programs, the Commission found that for Hurricane Irma, hardened feeders performed significantly better than

[2] *See* footnote 1.

non-hardened feeders with respect to outage rates, pole failures, and CMH required to restore power.[3]

FPL expects to harden approximately 250-350 feeders annually, with 100% of FPL's feeders expected to be hardened or underground by year-end 2024 and with the final costs of the program to be incurred in 2025. The total estimated costs for the Feeder Hardening (EWL) – Distribution Program for the period of 2020-2025 is $3,206 million with an annual average cost of approximately $534 million, which is consistent with historical costs for the existing distribution feeder hardening program.[4] A detailed description of the Feeder Hardening (EWL) – Distribution Program is provided in Section IV(C) of FPL's SPP.

Q. Please provide a summary of FPL's Lateral Hardening (Undergrounding) - Distribution Program included in the SPP.

A. The Lateral Hardening (Undergrounding) - Distribution Program included in the SPP is a continuation and expansion of FPL's existing three-year Storm Secure Underground Program Pilot ("SSUP Pilot") implemented in 2018. The SSUP Pilot is a program that targets certain overhead laterals that were impacted by recent storms and have a history of vegetation-related outages and other reliability issues for conversion from overhead to underground. As part of its proposed SPP, FPL will complete its existing three-year SSUP Pilot in 2020 and expand the application of the SSUP during 2021-2029 to the implementation of the system-wide Lateral Hardening (Undergrounding) – Distribution Program to provide the benefits of underground lateral hardening throughout its system. As explained in the SPP, the proposal to continue and expand the application of the SSUP under the SPP is based on the performance of the

[3] *See Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018*, Docket No. 20170215-EU (July 24, 2018).

[4] *See* footnote 1.

underground facilities as compared to overhead facilities and the extensive damage to the overhead facilities caused by vegetation during Hurricanes Matthew and Irma.

By the end of 2020, the third and final year of the SSUP Pilot, FPL expects to have converted a total of 220-230 laterals from overhead to underground, which is consistent with the SSUP Pilot plan most recently approved in July 2019 in FPL's most recent storm hardening plan docket, Docket No. 20180144-EI. After completing the SSUP Pilot in 2020, FPL estimates that it will convert approximately 300-700 laterals annually in 2021-2023 and approximately 800-900 laterals annually in 2024-2029. The total estimated costs for the Lateral Hardening (Undergrounding) - Distribution Program for the ten-year period of 2020-2029 is $5,101 million with an annual average cost of approximately $510 million.[5] A detailed description of the Lateral Hardening (Undergrounding) - Distribution Program is provided in Section IV(D) of FPL's SPP.

Q. Please provide a summary of FPL's Wood Structures Hardening (Replacing) – Transmission Program included in the SPP.

A. The Wood Structure Hardening (Replacing) – Transmission Program included in the SPP is a continuation of FPL's existing transmission hardening program to replace all wood transmission structures with steel or concrete structures. As explained in the SPP, the performance of FPL's transmission facilities during recent storm events indicates FPL's transmission hardening program has contributed to the overall storm resiliency of the transmission system and provided savings in storm restoration costs.

As of year-end 2019, 96% of FPL's transmission structures, system-wide, were steel or concrete, with less than 2,900 (or 4%) wood structures remaining to be replaced. FPL expects

[5] *See* footnote 1.

to replace the 2,900 wood transmission structures remaining on its system by year-end 2022. The total estimated costs for the Wood Structure Hardening (Replacing) – Transmission Program for the period of 2020-2022 is $118 million with an annual average cost of approximately $39 million, which is a decrease from the historical costs for the existing transmission hardening program.[6] A detailed description of the Wood Structure Hardening (Replacing) – Transmission Program is provided in Section IV(E) of FPL's SPP.

Q. Please provide a summary of FPL's Substation Storm Surge/Flood Mitigation Program.

A. The Substation Storm Surge/Flood Mitigation Program is the only new storm hardening program that FPL proposes to implement as part of its SPP. The Storm Surge/Flood Mitigation – Transmission and Distribution Program will implement measures to protect T&D substations and equipment that are susceptible to storm surge or flooding due to extreme weather events.

Historically, several FPL distribution and transmission substations have been impacted by storm surge and/or flooding as a result of extreme weather conditions. While proactively de-energizing those substations impacted by storm surge and/or flooding helps reduce damage to substation equipment, FPL is still required to implement both temporary flood mitigation efforts and repairs to substation facilities and equipment that become flooded as a result of extreme weather conditions. Further, flooding and the need to proactively de-energize substations located in areas susceptible to storm surge and flooding can result in significant customer outages. To prevent/mitigate future substation equipment damage and customer outages due to storm surge and flooding, FPL's new Storm Surge/Flood Mitigation Program will raise the equipment at certain substations above the flood level and construct flood protection walls around other substations to prevent/mitigate future damage due to storm surge and flooding.

[6] *See* footnote 1.

At this time, FPL has identified between 8-10 substations where it initially plans to implement storm surge/flood mitigation measures over the next three years (2020-2022). The total estimated costs for the new Substation Storm Surge/Flood Mitigation over this three-year period is approximately $23 million with an annual average cost of approximately $8 million per year.[7] A detailed description of the Storm Surge/Flood Mitigation – Transmission and Distribution Program is provided in Section IV(F) of FPL's SPP.

Q. Please provide a summary of FPL's Vegetation Management – Distribution Program included in the SPP.

A. The Vegetation Management – Distribution Program included in the SPP is a continuation of FPL's existing, Commission-approved distribution vegetation management program. FPL's currently-approved distribution vegetation program, includes the following system-wide vegetation management activities: three-year cycle for feeders; mid-year cycle targeted trimming for certain feeders; six-year cycle for laterals; and continued education of customers through its Right Tree, Right Place initiative. In approving FPL's current distribution vegetation management cycles, the Commission indicated that FPL's distribution vegetation management cycles were cost-effective and would provide savings to customers. Additionally, as explained in the SPP, recent storm events demonstrate that FPL's existing distribution vegetation management program has contributed to the overall improvement in the resiliency of distribution system during storms, resulting in reductions in storm damage to poles, days to restore, and storm restoration costs.

Under the SPP, FPL plans to trim, on average, approximately 15,200 miles annually, including approximately 11,400 miles for feeders (cycle and mid-cycle) and 3,800 miles for laterals, which is consistent with the historic miles trimmed annually. The total estimated costs for the

[7] *See* footnote 1.

Vegetation Management – Distribution Program for the ten-year period of 2020-2029 is $596 million with an annual average cost of approximately $60 million, which is consistent with historical costs for the existing distribution vegetation management program.[8] A detailed description of the Vegetation Management – Distribution Program is provided in Section IV(G) of FPL's SPP.

Q. Please provide a summary of FPL's Vegetation Management – Transmission Program included in the SPP.

A. The Vegetation Management – Transmission Program included in the SPP is a continuation of FPL's existing transmission vegetation management program. The key elements of FPL's transmission vegetation management program are to inspect the transmission right-of-ways, document vegetation inspection results and findings, prescribe a work plan, and execute the work plan. In its SPP, FPL will continue its current transmission vegetation management plan, which includes visual and aerial inspections of all transmission line corridors, Light Detection and Ranging ("LiDAR") inspections of North American Electric Reliability Corporation's ("NERC") transmission line corridors, developing and executing annual work plans to address identified vegetation conditions, and identifying and addressing priority and hazard tree conditions prior to and during storm season. As explained in the SPP, the execution of FPL's transmission vegetation management plan has been and is a significant factor in mitigating damage to transmission facilities and avoiding transmission-related outages.

Under the SPP, FPL plans to inspect and maintain, on average, approximately 7,000 miles of transmission lines annually, including approximately 4,300 miles for NERC transmission line corridors and 2,700 miles for non-NERC transmission line corridors. This is comparable to the approximately 7,000 miles inspected and maintained annually, on average for 2017-2019.

[8] *See* footnote 1.

The total estimated costs for the Vegetation Management – Transmission Program for the ten-year period of 2020-2029 is $96 million with an annual average cost of approximately $10 million, which is consistent with historical costs for the existing transmission vegetation management program.[9] A detailed description of the Vegetation Management – Transmission Program is provided in Section IV(H) of FPL's SPP.

IV. ADDITIONAL DETAILS FOR FIRST THREE YEARS OF THE SPP

Q. Has FPL provided additional project-level details and information for the first year (2020) of the SPP?

A. Yes. The following additional information required by Rule 25-6.030(3)(e)(1), F.A.C., for the first year (2020) of the SPP is provided in Appendix E to FPL's SPP: (1) the actual or estimated construction start and completion dates; (2) a description of the affected existing facilities, including number and type(s) of customers served, historic service reliability performance during extreme weather conditions, and how this data was used to prioritize the proposed storm protection project; and (3) a cost estimate including capital and operating expenses. Additionally, a description of the criteria used to select and prioritize proposed storm protection projects is included in the description of each proposed SPP program provided in Section IV of the SPP.

Q. Does FPL's SPP provide sufficient detail to develop preliminary estimates of the rate impacts for the second and third years (2021-2022) of the SPP?

A. Yes. As required by Rule 25-6.030(3)(e)(2), F.A.C., FPL has provided the estimated number and costs of projects under each specific SPP program, which information was used to develop the estimated rate impacts for 2021-2022. This information is provided in Appendix C to FPL's SPP.

[9] *See* footnote 1.

Q. Did FPL provide a description of its vegetation management activities under the SPP for the first three years (2020-2022) of the SPP?

A. Yes. The following additional information required by Rule 25-6.030(3)(f), F.A.C., for the first three years (2020-2022) of the vegetation management activities under the SPP is provided in Sections IV(G) and IV(H) of FPL's SPP and Appendix C to FPL's SPP: the projected frequency (trim cycle); the projected miles of affected transmission and distribution overhead facilities; and the estimated annual labor and equipment costs for both utility and contractor personnel. Additionally, descriptions of how the vegetation management activities will reduce outage times and restoration costs due to extreme weather conditions are provided in Sections IV(G) and IV(H) of FPL's SPP.

Q. Has FPL provided the annual jurisdictional revenue requirements for the 2020-2029 SPP?

A. Yes. Pursuant to Rule 25-6.030(3)(g), F.A.C., FPL has provided the estimated annual jurisdictional revenue requirements in Section VI of the SPP. While FPL has provided estimated costs by program as of the time of this filing and associated total revenue requirements in its SPP, consistent with the requirements of Rule 25-6.030, F.A.C., subsequent projected and actual program costs submitted for cost recovery through the Storm Protection Plan Cost Recovery Clause (per Rule 25-6.031, F.A.C.) could vary by as much as 10-15%, which variations would also impact the associated estimated revenue requirements and rate impacts. The projected costs, actual/ estimated costs, actuals costs, and true-up of actual costs to be included in FPL's Storm Protection Plan Cost Recovery Clause will all be addressed in subsequent filings in separate Storm Protection Plan Cost Recovery Clause dockets pursuant to Rule 25-6.031, F.A.C.[10]

Q. Has FPL estimated the rate impacts for each of the first three years of the SPP?

[10] The Commission has opened Docket No. 20200092-EI to address Storm Protection Plan Cost Recovery Clause petitions to be filed the third quarter of 2020.

A. FPL anticipates the programs included in the SPP will have zero bill impacts on customer bills during the first year of the SPP and only minimal bill increases for years two and three of the SPP. An estimate of the hypothetical overall rate impacts for the first three years of the SPP (2020-2022) based on the total program costs reflected in this filing, without regard for the fact that FPL remains under a general base rate freeze pursuant to a Commission-approved settlement agreement through December 31, 2021, are provided in Section VII of the SPP. The projected costs, actual/estimated costs, actuals costs, and true-up of actual costs to be included in FPL's Storm Protection Plan Cost Recovery Clause will all be addressed in subsequent filings in separate storm protection plan cost recovery clause dockets pursuant to Rule 25-6.031, F.A.C.[11]

V. CONCLUSION

Q. Does FPL believe that its SPP will achieve the legislative objectives of Section 366.96, F.S., to reduce costs and outage times associated with extreme weather events by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management?

A. Yes. While no electrical system can be made completely resistant to the impacts of hurricanes and other extreme weather conditions, FPL's SPP provides a systematic approach to achieve the legislative objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. As explained above and in further detail in the SPP, FPL's SPP programs are largely a continuation and expansion of FPL's already successful and ongoing storm hardening and storm preparedness programs previously approved by the Commission, as well as a new storm hardening program to protect T&D substations and equipment from storm surge and flooding due to extreme weather events. These SPP programs

[11] *See* footnote 10.

will continue to provide increased T&D infrastructure resiliency, reduced restoration time, and reduced restoration costs when FPL's system is impacted by extreme weather events. FPL's SPP appropriately and effectively maintains and builds on FPL's commitment to provide safe and reliable electric service to customers, and to meet the needs and expectations of our customers, today and for many years to come.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Scott Norwood for Docket No. 20200067-EI was inserted.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Scott Norwood. I am President of Norwood Energy Consulting, L.L.C. My business address is P.O. Box 30197, Austin, Texas 78755-3197.

Q. WHAT IS YOUR OCCUPATION?

A. I am an energy consultant specializing in the areas of electric utility regulation, resource planning, and energy procurement.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have over 37 years of experience in the electric utility industry. After graduating from the University of Texas with a Bachelor of Science degree in electrical engineering, I began my career as a power plant engineer for the City of Austin's Electric Utility Department where I was responsible for electrical maintenance and design projects for the City's three gas-fired power plants. In January 1984, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Manager of Power Plant Engineering, and in that capacity, was responsible for addressing resource planning, fuel, and purchased power cost issues presented in regulatory filings before the PUCT. In 1986, I joined GDS Associates, Inc., an electric utility consulting firm, where I served as a Principal and Director of the firm's Deregulation Services Department for 18 years. In January 2004, I founded Norwood Energy Consulting, LLC, which is based in Austin, Texas. The focus of my current consulting practice is providing regulatory consulting and expert witness services to organizations representing consumers of electricity on matters related to electric utility economic, operational, and planning issues.[1]

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the Citizens of the State of Florida ("Citizens") through the Office of Public Counsel ("OPC").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE UTILITY REGULATORY COMMISSIONS OR THE FLORIDA PUBLIC SERVICE COMMISSION ("FPSC" OR "COMMISSION")?

A. Yes, I have testified before both. I have filed testimony in over 200 electric utility regulatory proceedings involving electric restructuring, base rate, fuel recovery, power plant certification, and demand-side management matters before state regulatory commissions in Arkansas, Alaska, Florida, Georgia, Illinois, Iowa, Kentucky, Louisiana, Michigan, Missouri, New Jersey, Ohio, Oklahoma, Texas, Virginia, Washington, and Wisconsin. I filed testimony on behalf of OPC in FPSC Docket No. 20130140-EI, a proceeding involving Gulf Power Company's application for approval of a transmission-related solution to an environmental compliance plan for the Company's coal-fired generating stations. That case was settled before hearing. I have also filed testimony addressing Duke Energy Florida LLC's proposed Storm Protection Plan ("SPP") in pending FPSC Docket No. 202000069-EI, and in a number of other utility transmission and distribution grid hardening and grid modernization proposals and T&D reliability issues in regulatory proceedings over the last several years in Arkansas, Iowa, Oklahoma, Texas, and Virginia.

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1 *See* Direct Exhibit SN-1 for a more detailed summary of my background and experience.

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

A. The purpose of my testimony is to present my conclusions and recommendations regarding Tampa Electric Company's ("TECO" or "Company") application for approval of a Storm Protection Plan ("SPP" or "the Plan") for the ten-year period 2020-2029, pursuant to rule 25-6.030, F.A.C. ("SPP Rule").

Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR TESTIMONY?

A. Yes. I have prepared 3 exhibits which are included with my testimony.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS BASED ON YOUR REVIEW OF TECO'S SPP.

A. My testimony addresses the reasonableness of TECO's proposed SPP, which is expected to cost $1.92 billion for deployment over the next ten years. The purpose of the SPP is to reduce outage time and restoration costs associated with "extreme weather events" ("EWE") through hardening of TECO's Transmission and Distribution (T&D) grid, undergrounding of distribution lines, and vegetation management programs. My primary conclusions regarding TECO's proposed SPP are as follows:

1) TECO's proposed SPP is expected to cost $1.92 billion over the next ten years. The Company has barred review of details regarding its CBA calculations that are essential to confirm the reasonableness of the CBA results; therefore, the claimed benefits and cost-effectiveness of the SPP cannot be verified. TECO's lack of transparency regarding its CBA

calculations needlessly complicates the Commission's review and is unusual for an investment of this magnitude.

2) The estimated benefits included in TECO's CBA for the SPP are inflated by the inclusion of forecasted EWE outage impacts that are nearly 3 times the EWE outage minutes incurred since 2006, after adjusting for the extraordinary impact of Hurricane Irma. Even with this problem, which inflates forecasted benefits and has not been explained by the Company, TECO's CBA indicates that the total cost of the SPP is more than $1 billion higher (3.7 times) the forecasted electric benefits of the Plan, and that only one proposed program, the Substation Extreme Hardening Program, is expected to be cost-effective.

3) TECO's CBA for the SPP did not evaluate alternatives to selected programs, including potentially lower-cost alternatives, such as delaying or scaling back the proposed $1.92 billion SPP.

4) TECO has provided high service reliability over the last ten years, with customers receiving electric service in 99.98% of all hours, including EWE outages that contribute approximately 20 minutes of outage time per customer per year on average. The forecasted improvement with the $1.92 billion SPP is relatively small, and would likely increase TECO's annual service reliability by less than 0.004%.

5) Given the high cost of the proposed SPP, and the fact that the Plan is not urgently needed in its current magnitude, it would be prudent for TECO to delay implementation of the proposed SPP until the economic impacts of the COVID-19 pandemic are more certain, and so that potentially less costly alternatives to the SPP can be evaluated.

Based on the above, I recommend that the Commission consider approving a modified Plan contingent upon TECO's filing of an updated Plan in 2022, so that analysis of alternatives to the SPP can be conducted, and so longer-term COVID-19 impacts on Plan costs and implementation can be further evaluated.

III. SUMMARY OF TECO'S SPP APPLICATION

Q. PLEASE DESCRIBE TECO'S SERVICE AREA AND EXISTING TRANSMISSION AND DISTRIBUTION SYSTEM.

A. As of January 1, 2020, TECO served approximately 794,953 retail electric customers located in a service area covering approximately 2,000 square miles in West Central Florida.[2] TECO has 1,350 miles of overhead facilities, including 25,416 transmission poles, and approximately 9 miles of underground transmission facilities. The Company's distribution system consists of 6,300 miles of overhead lines, 404,000 poles, approximately 5,100 circuit miles of underground facilities, and 216 substations.[3]

Q. PLEASE DESCRIBE TECO'S PROPOSED SPP APPLICATION.

A. In 2019, the Florida Legislature enacted section 366.96, Florida Statutes, ("SPP Statute"), which requires Florida utilities to prepare and file 10-year Storm Protection Plans, at least every three years. The SPP Statute specifies that, among other things, utility SPP filings "must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration

2 *See* TECO witness Chasse's Direct Testimony, page 5.
3 *See* TECO witness Chasse's Direct Testimony, pages 6-7.

costs and outage times associated with extreme weather events and enhancing reliability."[4]

As directed by the SPP Statute, the FPSC enacted rules to establish specific filing requirements and administrative procedures for review and approval of utility SPP filings and related cost recovery mechanisms. In this case, TECO is requesting Commission-approval of an SPP for the 10-year period 2020-2029, pursuant to the SPP Rule, which establishes required elements of the SPP filing, including descriptions of the programs, specific projects, and summaries of proposed costs for implementing the first three years of the SPP (2020-2022).

Q. HAVE EXTREME WEATHER EVENTS HAD A MAJOR IMPACT ON TECO'S SYSTEM OVER TIME?

A. There have been relatively few EWEs on TECO's system over time. For example, according to data presented in TECO's proposed SPP, since 1852 there have only been approximately 184 EWEs (on average 1.1 events per year) that have impacted TECO's service area.[5]

Q. IS THE SPP THE COMPANY'S FIRST MAJOR INITIATIVE TO REDUCE OUTAGE TIME AND OUTAGE RESTORATION COSTS RELATED TO MAJOR STORM EVENTS?

A. No. The SPP appears to be largely a continuation of TECO's Storm Hardening Plan ("SHP"), which has been filed with the Commission every three years

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4 Section 366.96(3), Florida Statutes. While the term "extreme weather event" is not defined in the SPP Statute or SPP Rule, the Commission's rules governing Annual Distribution Service Reliability Reports suggest that the term EWE generally been used to refer to named tropical storms and hurricanes, ice storms, and other extreme events such as tornados.

5 *See* TECO witness De Stigter's Direct Testimony, page 29, Table 4.

since 2007, pursuant to Commission Rule 25-6.0432. The Commission's rules describe the purpose of the SHP as follows:

> [T]o ensure the provision of safe, adequate, and reliable transmission and distribution service for operational as well as emergency purposes; require the cost-effective strengthening of critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions; and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions.

TECO's most recent SHP for the 2019-2021 period was filed in March 2019 and approved by the Commission in July 2019.[6]

Q. WHAT IS THE PROPOSED SCOPE AND ESTIMATED COST OF TECO'S PROPOSED SPP?

A. As summarized in Table 1, TECO proposes to expend approximately $1.92 billion over the 2020-2029 period for programs and projects involving overhead hardening of transmission and distribution ("T&D") facilities, undergrounding of certain distribution lines, and enhanced vegetation management that it asserts are intended to reduce restoration costs and outage times to customers related to EWE.[7] The Distribution Lateral Undergrounding, T&D Vegetation Management and Distribution Overhead Feeder Hardening Programs make up over 81% of the total SPP cost over the first ten years.

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6 *See* the Commission's Final Order dated July 29, 2019, in FPSC Docket No. 20180145-EI. It is my understanding that since the time of the SHP Final Order, the SHP Rule has been repealed but the approved SHP remains in effect.

7 *See* TECO witness Chasse's Direct Testimony, page 10.

Table 1
Projected Cost of TECO's SPP
2020-2029 ($Millions)[8]

SPP Program	Capital	O&M	Total	% of Total
Distribution Lateral Undergrounding	$976.8	$0.0	$976.8	50.9%
T&D Vegetation Management	$0.0	$291.4	$291.4	15.2%
Transmission Asset Upgrades	$149.1	$3.0	$152.1	7.9%
Substation Extreme Weather Hardening	$32.4	$0.0	$32.4	1.7%
Distribution Overhead Feeder Hardening	$289.7	$8.9	$298.6	15.5%
Transmission Access Enhancements	$14.7	$0.0	$14.7	0.8%
Distribution Infrastructure Inspections	$0.0	$10.5	$10.5	0.5%
Transmission Infrastructure Inspections	$0.0	$5.1	$5.1	0.3%
SPP Planning & Common	$0.0	$3.1	$3.1	0.2%
Other Legacy SH Plan Initiatives	$0.0	$3.0	$3.0	0.2%
Distribution Pole Replacements	$126.1	$6.9	$133.0	6.9%
Total 10-Yr SPP Cost	$1,588.8	$331.8	$1,920.6	100.0%

Q. HOW MUCH HAS TECO EXPENDED OR INVESTED UNDER PAST STORM HARDENING PLANS FOR GRID HARDENING TO REDUCE IMPACTS OF MAJOR STORMS?

A. TECO indicates that it has expended or invested approximately $679 million since 2007 for SHP projects, much of which includes grid hardening and vegetation management enhancements similar to the programs proposed in the current SPP.[9]

Q. WHAT HAS BEEN THE FREQUENCY, DURATION AND COST OF EWE OUTAGES ON TECO'S SYSTEM SINCE 2006?

8 Source is the 10-year SPP Program cost summary provided on page 67 of TECO's 2020-2029 SPP Report.

9 Source is TECO's response plus referenced attachment to OPC Interrogatory 6-198.

A. TECO indicates it does not have records regarding EWE outage time or restoration costs that impacted its system before 2006.[10] However, as shown in Table 2 below, since 2006 TECO's system has been impacted by approximately 1 EWE per year, and these events increased TECO's outages to customers by an average of 68 minutes per year and increased TECO's SAIFI by 0.08 outages per customer per year. These EWE impacts are small, and they would have been much smaller except for the extraordinary impact of Hurricane Irma in 2017, which represented approximately 83% of the total EWE outage time on TECO's system since 2006.

Table 2
TECO's Extreme Weather Event Outage History[11]

Year	# of Events	SAIDI Impact	SAIFI Impact
2006	1	7.2	0.01
2007	1	5.5	0.08
2008	0	0.0	0.00
2009	0	0.0	0.00
2010	0	0.0	0.00
2011	1	75.5	0.15
2012	2	28.4	0.13
2013	2	3.5	0.02
2014	1	1.1	0.01
2015	0	0.0	0.00
2016	3	34.6	0.19
2017	2	792.8	0.47
2018	0	0.0	0.00
2019	1	1.2	0.02
Total	14	949.8	1.08
Average	1	67.8	0.08

Q. WHAT DO THE HISTORICAL EWE DATA IN TABLE 2 SUGGEST REGARDING THE IMPACTS OF EWE-RELATED OUTAGES ON TECO'S SYSTEM?

10 Source is TECO's response to OPC Interrogatory 3-98.
11 Source is TECO's response to OPC Interrogatory 3-98.

A. The data in Table 2 indicates that EWE-related outages have had a very small impact on TECO's system since 2006. The 68 minutes of average EWE SAIDI time including Hurricane Irma equates to only 0.013% of total annual minutes. If the average EWE outage time is adjusted to normalize the impact of Hurricane Irma, one of only two Category 4 storms that have impacted TECO's system since 1852, the average EWE impact on TECO's SAIDI is approximately 20 minutes per customer per year.[12] This 20 minutes equates to approximately 0.004% of annual minutes. Assuming the SPP is able to reduce 50% of TECO's historical average EWE outage time, this means that the EWE outage reduction benefit of the Plan would be approximately 10 minutes per customer per year, or 0.002% of annual minutes. This is a very small potential outage reduction benefit of the SPP, which most TECO customers would probably not notice.

Q. HAVE ANY OF THE PROGRAMS IN TECO'S PROPOSED SPP BEEN DEPLOYED BY THE COMPANY AS PART OF PAST SHPS?

A. Yes. Some of the proposed SPP programs have been deployed by TECO as part of past SHP projects; however, there are several new programs,[13] including the Distribution Lateral Undergrounding Program, the Substation Extreme Hardening Program, the Distribution Overhead Feeder Hardening Program, and Vegetation Management Program Enhancements.

Q. WHAT ARE THE ESTIMATED REVENUE REQUIREMENTS FOR TECO'S PROPOSED SPP OVER THE TEN-YEAR PLAN PERIOD?

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12 *See* Exhibit SN-2, SAIDI adjustment for Hurricane Irma.

13 *See* pages 9 and section 6 of TECO's 2020-2029 SPP Report.

A. The total estimated revenue requirement of TECO's proposed SPP over the 2020-2029 plan period is approximately $972 million.[14] It should be noted that the above revenue requirements do not reflect additional deployment and operational costs of the proposed SPP programs that would be incurred for full deployment of the Plan beyond 2029.

B.

Q. WHAT IS THE ESTIMATED RATE IMPACT OF TECO'S PROPOSED SPP ON RESIDENTIAL CUSTOMERS?

A. TECO estimates that the proposed SPP investments will increase monthly electric charges to a residential customer that uses 1,000 kWh per month by approximately $2.22 per month in 2021, and by $3.09 per month in 2022.[15] These TECO rate impact estimates are incremental rate impacts that exclude related costs of the SPP that have historically been recovered in base rates.

Q. HOW HAVE YOU EVALUATED THE REASONABLENESS OF TECO'S PROPOSED SPP?

A. My testimony focuses on three primary issues: 1) the extent to which TECO has demonstrated that the proposed SPP is cost-effective and represents the lowest reasonable cost alternative for addressing identified forecasted needs to reduce EWE outage durations and restoration costs; 2) whether TECO's proposed SPP programs are needed to reduce EWE outage time and outage restoration costs; and 3) whether it is essential and prudent for TECO to proceed with such a large project at a time when its customers are facing great economic uncertainty as a result of the COVID-19 pandemic.

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14 *See* the 10-year SPP revenue requirements summary provided on page 70 of TECO's 2020-2029 SPP Report.

15 Source is TECO witness Chasse's Direct Testimony, page 29.

IV. COST EFFECTIVENESS OF PROPOSED SPP

Q. HOW IS THE COST EFFECTIVENESS OF PROPOSED MAJOR UTILITY INVESTMENTS TYPICALLY EVALUATED IN REGULATORY PROCEEDINGS?

A. Once the need for an investment to ensure reliable electric service is established, the cost-effectiveness of the investment is typically evaluated through cost-benefit analyses, which are generally designed to determine whether projects are cost-effective, and the lowest reasonable cost alternative to supply the identified need, with due consideration given to uncertainty in major assumptions used for the analysis.

Q. HAS TECO PROVIDED A CBA THAT DEMONSTRATES THAT ITS SPP IS COST-EFFECTIVE AND THE LOWEST REASONABLE COST ALTERNATIVE TO REDUCE EWE OUTAGE TIME AND COSTS?

A. No. In fact, as summarized in Table 3 below, TECO's CBA indicates that its SPP is not cost-effective, with the estimated costs of the SPP being more than $1.0 billion (3.7 times) higher than the forecasted benefits of the SPP.

Table 3
TECO CBA Results for SPP Programs
(for P50 Outage Scenario)[16]

SPP Programs	SPP Program Costs	EWE Outage Benefits	Net Benefit/(Cost)	Ben/Cost Ratio
Distribution Lateral Undergrounding	$976,900,000	$234,790,464	($742,109,536)	0.24
Transmission Asset Upgrades	$148,900,000	$57,962,916	($90,937,084)	0.39
Substation Extreme Weather Hardening	$32,300,000	$34,988,866	$2,688,866	1.08
Distribution Feeder Hardening	$289,600,000	$66,105,759	($223,494,241)	0.23
Transmission Access Enhancements	$14,800,000	$3,005,945	($11,794,055)	0.20
Total SPP Plan	$1,462,500,000	$396,853,950	**($1,065,646,050)**	**0.27**
	3.7			

Moreover, TECO's CBA does not evaluate other potentially lower cost alternatives to the SPP on the basis of net electric cost benefits to customers;[17] therefore, the CBA does not demonstrate that TECO's SPP is the lowest reasonable cost alternative to reduce EWE outages and outage restoration costs to customers.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE MANNER IN WHICH TECO'S CBA WAS CONDUCTED AND PRESENTED IN THIS CASE?

A. Yes. I have four primary concerns regarding TECO's CBA for the SPP. First, the Company has not provided details regarding the CBA calculations for proposed SPP programs, as required by Rule 25-6030(3)(d), F.A.C. While the Company has provided summary results for the total estimated costs and

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16 Source is TECO's response to OPC Interrogatory 6-196.

17 TECO's response to OPC Interrogatory 6-196 shows that the Company's cost-benefit analysis of alternatives included $4 billion of non-electric customer benefits. Without these benefits, none of the SPP Programs except the Substation Extreme Hardening Program, are forecasted to provide net electric cost benefits to customers.

benefits of each proposed SPP program, and a summary of major input assumptions, the Company claims that because the analysis was developed using a proprietary model, details as to how referenced benefits and costs were calculated for each SPP program, a breakdown of the total costs and benefits by type, or the calculations of the benefit/cost ratios for each proposed program, cannot be provided to OPC or other parties in this case.[18] This claimed barrier to access to the details of the CBA calculations is problematic and extraordinary for a case involving a request for approval of a $1.92 billion investment.

The second major flaw in TECO's CBA for the SPP is that many details regarding the Storm Modeling calculations supporting the forecasted EWE storm impacts on TECO's system, are not available to OPC or other parties, again because of claims that such disclosure would require release of proprietary information on the storm model.[19] Moreover, the Storm Modeling results appear to overstate the EWE outage time and outage restoration costs when compared to the very low EWE impacts that historically have been experienced on TECO's system. For example, the Company's CBA forecasts that the SPP would reduce EWE outage time by approximately 29 minutes per customer per year over the next 50 years, which is nearly 3 times the EWE outage minutes incurred since 2006, after adjusting for the extraordinary impact of Hurricane Irma. However, without having access to details of TECO's storm model calculations, there is no way to determine that the model is operating properly, because the model has not been used or reviewed in any other regulatory proceeding, and has not been benchmarked to determine whether it is reasonably forecasting storm impacts for TECO's system.[20]

18 *See* TECO's responses to OPC Interrogatories 2-49 and 2-50.
19 *See* TECO's responses to OPC Interrogatories 2-52 and 5-138.
20 *See* TECO's responses to OPC Interrogatories 5-154 and 5-155.

Again, in my experience it is unusual and problematic for details regarding an essential modeling function (such as TECO's storm forecast) to be obscured from review, particularly in a proceeding involving a $1.92 billion proposed investment, such as TECO's SPP.

The third primary flaw in TECO's CBA for the SPP is that the Company did not evaluate or present potentially lower cost alternatives to the $1.92 billion Plan, except for analyses that included non-electric customer benefits.[21] For example, two plausible and potentially less costly alternatives to the SPP would be: 1) to refine the Plan to continue with the Company's current practice of strategically addressing worst performing circuits until there is an observed need to improve T&D reliability performance, and 2) to significantly reduce the scale and investment level of the SPP in light of the already very high service reliability and small impacts of EWE outages on TECO's system. TECO's failure to evaluate net electric benefits to customers for less costly alternatives in conjunction with the CBA of the SPP means that there is no basis to conclude that the SPP is the lowest reasonable cost alternative to improve reliability, if the Company had such a need.

The fourth primary flaw in TECO's CBA for the SPP is that it includes approximately $4 billion of non-electric customer benefits for the purpose of selection and prioritization of programs included in the SPP. These estimated non-electric customer benefits include items such as EWE outage related costs and lost revenues that are theoretically avoided by reducing outages. It is not appropriate to include such speculative non-electric benefits to justify selection of a major electric utility investment such as the SPP.

21 *See* TECO's response to OPC Interrogatory 6-186 and Figure 1-2 on page 99 of TECO's SPP Benefits and Assessment Report.

Q. WHAT ARE YOU ABLE TO CONCLUDE REGARDING THE RESULTS OF TECO'S CBA FOR THE SPP WITHOUT HAVING ACCESS TO DETAILS OF THE COMPANY'S CBA OR STORM MODELING CALCULATIONS?

A. I am unable to conclude whether forecasted storm impacts or related benefits of the SPP presented in TECO's testimony are reasonably estimated; however, as noted earlier in my testimony, the information provided in TECO's SPP filing and discovery responses indicate that the forecasted EWE outage time for the SPP CBA is approximately 3 times the average EWE outage time on TECO's system, which means that the SPP outage reduction benefits are unreasonably inflated. Notwithstanding this flaw, and the fact that OPC and other parties were not allowed to see details of the Company's CBA calculations or storm modeling calculations, TECO's CBA analysis still shows that the cost of the proposed SPP is approximately $1 billion higher (3 times higher) than the forecasted electric cost benefits to TECO's customers.

In fact, as noted in Table 3 of my testimony, TECO's CBA indicates that only one of the proposed SPP programs — the Substation Extreme Hardening Program — is expected to be cost-effective. That program has an estimated 10-year deployment cost of approximately $32.3 million, which is approximately 2.2% of the $1.92 billion total SPP deployment cost for the 2020-2029 period. Although TECO's estimated benefits of the Substation Extreme Hardening Program cannot be verified, one option the Commission could consider would be to allow TECO to proceed with that program and to re-evaluate the need for and cost-effectiveness of other SPP program alternatives in the Company's next SPP filing.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COST-EFFECTIVENESS OF TECO'S PROPOSED SPP?

A. TECO has not provided details necessary to verify the reasonableness of the high-level CBA and Storm Modeling summary results it has provided for the SPP. From the information that was provided by TECO, it is apparent that the CBA analysis includes inflated benefits estimates due to its inclusion of unrealistically high forecast of future EWE outage impacts without the SPP, therefore overstating potential benefits of SPP programs. Moreover, the Company's CBA for the SPP did not evaluate the electric cost benefits of potentially lower cost alternatives to the Plan and includes several programs for which there are no forecasted net electric cost benefits for customers. Given these facts, it would be imprudent for TECO to proceed with the $1.92 billion SPP initiative, particularly when the Company already has very high T&D service reliability including EWE outages, and because the potential reliability improvements from the SPP will be too small for most TECO customers to notice.

V. NEED FOR PROPOSED SPP

Q. WHAT STANDARDS ARE TYPICALLY APPLIED BY REGULATORY COMMISSIONS TO DECIDE WHETHER MAJOR UTILITY INVESTMENTS ARE PRUDENT AND SHOULD BE APPROVED?

A. In my experience, most regulatory commissions evaluate major electric utility investments such as the SPP based on three primary factors: 1) whether the Project is needed to ensure reasonable and reliable electric service; 2) whether the proposed Project is cost-effective and the lowest reasonable cost alternative; and 3) whether such investments are justified in light of uncertainty in market conditions at the time they are proposed.

Q. HOW DO YOU MEASURE THE RELIABILITY OF ELECTRIC UTILITY T&D SERVICE TO CUSTOMERS?

A. Electric T&D service reliability is most commonly measured by two performance metrics: 1) the System Average Interruption Frequency Index ("SAIFI"), which represents the average number of outages per customer per year; and 2) the System Average Interruption Duration Index ("SAIDI"), which is the average duration of T&D outages per customer per year, expressed in minutes. Often these two reliability metrics are reported with and without the impacts of extreme weather events, such as hurricanes or tornados, which are difficult to control. In fact, the Commission's rules require that TECO and other utilities file Annual Distribution Reliability Reports each year, and specifies that reliability data be provided with and without adjustments to remove impacts of EWEs.[22]

Q. HAS TECO'S T&D RELIABILITY PERFORMANCE BEEN REASONABLE OVER THE LAST TEN YEARS?

A. Yes. While I have not examined the performance of each of TECO's T&D circuits, on the whole, the Company's service reliability has been very good over the last ten years. For example, as summarized in Table 4 below, TECO's customers have experienced approximately 1.37 outages per year and approximately 102 minutes per year of service interruption time, including impacts of Hurricane Irma and other EWEs. This performance means that on average, over the last 10 years TECO's customers have received electric service in 99.98% of the hours each year, including impacts of major storm events (with Hurricane Irma). This past performance of TECO's system

22 *See* FPSC Rule 25-6.0455, Annual Distribution Service Reliability Report.

indicates the Company has provided very high service reliability to customers without the SPP.

Table 4
TECO's Distribution System Reliability Performance[23]

	SAIFI (# of Outages) Incl EWE	SAIFI (# of Outages) Excl EWE	SAIDI (Outage Minutes) Incl EWE	SAIDI (Outage Minutes) Excl EWE
2010	1.21	1.06	92.20	88.73
2011	1.48	1.17	158.49	80.95
2012	1.30	0.98	112.35	80.80
2013	1.37	1.09	99.26	89.54
2014	1.26	1.03	86.49	81.71
2015	1.33	1.12	87.93	84.27
2016	1.34	1.12	98.63	86.16
2017	1.32	1.10	85.58	74.78
2018	1.62	1.32	111.33	98.16
2019	1.48	1.20	92.32	78.89
2010-19 Average	1.37	1.12	102.46	84.40

Q. HOW DOES TECO'S 99.98% SERVICE RELIABILITY COMPARE TO THE RELIABILITY PROVIDED BY OTHER INVESTOR-OWNED ELECTRIC UTILITIES?

A. As shown in Table 5 below, TECO's T&D SAIDI and reliability performance over the 2014-2018 period compared favorably to the performance of other Florida electric utilities, and the Company's SAIDI performance including EWEs ranked 6th best out of a comparison group of 89 investor-owned utilities serving more than 300,000 customers during 2018, the most recent period for which national data from the Energy Information Administration ("EIA") is available.[24]

23 Sources are TECO's responses to OPC Interrogatories 2-46 and 2-47.
24 *See* Exhibit SN-3, EIA 861 Reliability Survey data.

Table 5
Florida IOU SAIDI and Reliability Performance[25]
(2014-2018 Average)

	SAIDI	Average
DEF	86.4	99.98%
FPL	57.2	99.99%
FPUC	156.0	99.97%
GULF	96.8	99.98%
TECO	82.0	99.98%

In summary, TECO's historical T&D service reliability, even with impacts of EWE outages (including Hurricane Irma), has been very high, comparable to other Florida utilities and better than most electric utilities in the United States. Therefore, the Commission should not decide to approve the Company's proposed $1.92 billion investment for the SPP over the next ten years as being completely necessary from the perspective of reducing outages (to improve reliability) at this time.

Q. IS THERE ANY EVIDENCE THAT TECO'S CUSTOMERS ARE DISSATISFIED WITH THE COMPANY'S RELIABILITY PEFORMANCE?

A. There is evidence that TECO's customers are not dissatisfied with the Company's service reliability. For example, as summarized in Table 6 below, over the last ten years TECO has averaged approximately 117 complaints per year regarding the reliability of service it provides, which represents approximately 0.015% of the Company's 782,000 customers.

25 Source of reliability data are the FPSC Division of Engineering's November 2019 Report entitled "Review of Florida's Investor-Owned Electric Utilities 2018 Service Reliability Reports."

Table 6
TECO Customer Complaints
Related to T&D Reliability Issues[26]

	Complaints	Total Customers
2012	73.0	0.009%
2013	107.0	0.014%
2014	92.0	0.012%
2015	98.0	0.013%
2016	163.0	0.021%
2017	131.0	0.017%
2018	108.0	0.014%
2019	162.0	0.021%
Average:	116.8	0.015%

Note: % of Total assumes 782,400 total customers per pg 42 of SPP Benefits Report.

Q. ARE THERE OTHER INDICATORS OF THE LEVEL CUSTOMER SATISFACTION AND ACCEPTANCE OF THE LEVEL OF TECO'S SERVICE RELIABILITY?

A. Yes; TECO offers an optional "Relay Service" tariff that allows customers to purchase higher than standard reliability.[27] However, since 2015 only approximately 30 of TECO's 782,000 customers have opted for this premium service, which indicates broad customer acceptance of TECO's current service reliability or perhaps the lack of interest by most customers to pay more for higher service reliability.[28]

Q. WOULD TECO'S T&D RELIABILITY BE GREATLY IMPROVED IF THE SPP IS IMPLEMENTED?

26 Sources are TECO's responses to OPC's PODs 2-20 and 2-21.
27 *See* TECO's response to OPC's POD 2-22.
28 *See* TECO's response to OPC's POD 2-22.

A. No. As discussed earlier in my testimony, TECO has averaged approximately 20 minutes per year of EWE-related outage time since 2006, including adjustments for the extraordinary impacts of Hurricane Irma. I understand that the Legislature determined that it is in the interest of the state to increase resilience and reliability. They appear to have been aware that TECO has expended hundreds of millions of dollars since 2006 on SHP programs to harden its T&D grid and for enhanced vegetation management programs to reduce outages and storm restoration costs. For this reason, it is important to note that in sections 366.96(3) and (4)(a) – (d), Fla. Stat., the Legislature required that the utilities explain the "systematic approach" they will "follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability."

I further understand that the Legislature also required the Commission to consider the extent to which the plan is expected to reduce restoration costs and outage times associated with extreme weather and enhance reliability, including whether the plan prioritizes area of lower reliability performance. They further required that the Commission consider the costs and benefits of making the improvements proposed in the plan and the rate impacts. In other words, the Legislature stated rather plainly that there is no presumption that the plan would be approved. Rather, it laid out tests of demonstration that the objectives would be achieved and those would be cost effective with an eye towards the impact on those who have to pay the costs.

In this regard, one of the fundamental concerns that I have is illustrated under the circumstance where, assuming that future EWE outages remain at the average 20 minute level reported since 2006, and that the SPP was able to eliminate 50% of total EWE outage time, which is not guaranteed, the improvement in TECO's reliability would only be approximately 10 minutes per customer per year, or 0.004% of total annual minutes. This means TECO's average service reliability including EWEs would increase the 99.98% reliability level including EWE outages over the last ten years without the SPP to a level of 99.984% with the SPP. Even if TECO guaranteed this very small improvement in reliability, which it has not, such a small improvement in reliability would not seem to justify the rate impact of the $1.92 billion TECO proposes to spend to deploy the SPP over the next 10 years, particularly under circumstances that may be clouded by the very real and affordability-threatening economic fallout of the COVID-19 pandemic. Given these circumstances, it seems premature for the Commission to fully approve TECO's plan to incur costs for SPP for 20 to 30 years beyond the proposed initial 10-year deployment period.

In summary, TECO's forecast that the $1.92 billion SPP initiative could be justified by the reduction in EWE outage time on its system is highly suspect given the high level of reliability of TECO's system (99.98% including EWEs) that has been achieved without the SPP, and the relatively small level (20 minutes per customer per year) of EWE outage time experienced by the Company's customers since 2006, including adjustments to normalize impacts of Hurricane Irma.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AS TO WHETHER THE SPP IS COST-EFFECTIVE AND NEEDED TO IMPROVE TECO'S T&D SERVICE RELIABILITY.

A. The SPP is not likely to materially improve TECO's T&D service reliability. TECO has provided highly reliable T&D service for at least the last ten years and is on a trajectory to provide highly reliable service as a result of the Company's significant past investments for Grid Hardening and Vegetation Management since the Company's SHPs were initially implemented in 2006. There is evidence that most of TECO's customers are not dissatisfied with

TECO's existing reliability service given the relatively small level of complaints filed related to service reliability and the general lack of customer interest in TECOs optional premium service tariff, which provides higher than standard reliability. Moreover, the small improvement in reliability performance that TECO claims would result from the SPP project is not guaranteed and has not been shown to be cost-effective as I discussed earlier in my testimony.

VI. ECONOMIC IMPACTS OF COVID-19 PANDEMIC

Q. SHOULD THE COMMISSION CONSIDER POTENTIAL ECONOMIC IMPACTS OF THE COVID-19 PANDEMIC IN DECIDING WHETHER TECO'S PROPOSED $1.92 BILLION SPP PROJECT SHOULD GO FORWARD AT THIS TIME?

A. Yes. The COVID-19 pandemic has already had tremendous adverse impacts on the U.S. and World economies as a result of widespread public health effects, travel restrictions, job loss and forced shutdown of many businesses. Although we are very early in the pandemic, and Florida has been affected less than many other states, the final economic impacts and effects on Florida, its citizens and the electric utility industry as a whole remain uncertain. Given this situation, I would recommend that the Commission require TECO to update its SPP on April 1, 2022, for COVID-19 impacts, including affordability and other downstream cost impacts driven by the related economic fallout. This update would accompany the robust CBA that I point out is lacking in this filing and would also give the Commission more visibility into any affordability impacts of the Plan and potential lower cost alternatives to the SPP. It would be prudent for the Commission at this time to delay full consideration of TECO's proposed SPP project until potential impacts of

COVID-19 on customers are more certain, particularly when it appears that there is no urgent need or demand for the very small projected reliability benefits that the Project might provide.

Given these facts, the Commission should be cautious in giving wholesale approval in today's environment to TECO's proposed $1.92 billion SPP initiative at this time. It is my understanding that Section 366.96(5), Fla. Stat., gives the Commission three options when confronted with a plan. It may approve the SPP as filed, it may reject the SPP, or it may approve the SPP with modification. Since the SPP statute requires the Commission to determine the rate impacts of the three-year horizon of each plan in conjunction with its disposition of the plans, the plain language of the statute requires customer rate impact and the affordability of the SPP be considered. Under the circumstances of the proposed SPP, where the Company has failed to file a CBA, where the proposed Plan carries a $1.92 billion price tag over ten years, and where there are numerous unresolved uncertainties associated with the economic impact of the COVID-19 pandemic, the Commission should proceed cautiously. Because the SPP statute requires the utilities to implement cost effective plans that would both enhance reliability and the resiliency of the grid, I do not believe that the Commission should approve the Plan as filed. Therefore, I recommend that the Commission modify the proposed SPP with the required CBA and a requirement that TECO re-file to consider the impact of the pandemic. Alternatively, I am recommending that the Commission temper any approval of the proposed SPP, with a requirement that the Company submit a plan update by April 1, 2022, that includes a cost benefit analysis that includes a complete and detailed demonstration of how the relevant costs and benefits are calculated. In addition, the Commission should require the Company to provide a complete discussion of how the long-term effects of the COVID-19 pandemic — including any severe economic ramifications — are expected to impact the affordability of electric service. This analysis should address the SPP as it proposes to implement the SPP costs of projects and programs as they are impacted by COVID-19. This analysis should further address the extent of how cost inputs such as fuel prices, labor costs and labor working conditions and other societal adjustments and cost inputs are expected to impact the costs included in the updated CBA underlying the SPP.

Q. HAS THE COMMISSION RECOGNIZED THE NEED TO CONSIDER SPECIAL REGULATORY RELIEF TO MITIGATE ECONOMIC IMPACTS OF COVID-19 TO FLORIDA ELECTRIC CUSTOMERS?

A. Yes. While it is in the early stages of this process, it is my understanding that the Commission has recently adopted proposals that would accelerate fuel cost refunds to customers in an effort to mitigate the economic impacts of COVID-19. I am also aware that in a different docket, the Commission's staff has asked for Duke Energy Florida, LLC ("DEF") to update assumptions and impacts of a large nuclear decommissioning and dismantlement proposal based on COVID-19 effects.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS REGARDING TECO'S PROPOSED SPP?

A. My primary conclusions regarding TECO's proposed SPP are as follows:

1) TECO's proposed SPP is expected to cost $1.92 billion over the next ten years. The Company has barred review of details regarding its CBA calculations that are essential to confirm the reasonableness of the CBA results; therefore, the claimed benefits and cost-effectiveness of the SPP cannot be verified. TECO's lack of transparency regarding its CBA

calculations needlessly complicates the Commission's review and is unusual for an investment of this magnitude.

2) The estimated benefits included in TECO's CBA for the SPP are inflated by the inclusion of forecasted EWE outage impacts that are nearly 3 times the EWE outage minutes incurred since 2006, after adjusting for the extraordinary impact of Hurricane Irma. Even with this problem, which inflates forecasted benefits and has not been explained by the Company, TECO's CBA indicates that the total cost of the SPP is more than $1 billion higher (3.7 times) the forecasted electric benefits of the Plan, and that only one proposed program, the Substation Extreme Hardening Program, is expected to be cost-effective.

3) TECO's CBA for the SPP did not evaluate alternatives to selected Programs, including potentially lower-cost alternatives, such as delaying or scaling back the proposed $1.92 billion SPP.

4) TECO has provided high service reliability 2006, with customers receiving electric service in 99.98% of all hours, including EWE outages. The forecasted improvement with the $1.92 billion SPP is relatively small, and would likely increase TECO's annual service reliability by approximately 0.004%.

5) Given the high cost of the proposed SPP, and the fact that the Plan is not urgently need in its current magnitude, it would be prudent for TECO to delay implementation of the SPP until the economic impacts of the COVID-19 pandemic are more certain, and so that potentially less costly alternatives to the SPP can be evaluated.

Based on the above, I recommend that the Commission consider approving with modifications TECO's proposed SPP contingent upon the filing of an updated Plan in 2022, so that analysis of alternatives to the SPP can be conducted, and so longer-term COVID-19 impacts on Plan costs and implementation can be further evaluated.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

(Whereupon, prefiled direct testimony of Scott Norwood for Docket No. 20200069-EI was inserted.)

DIRECT TESTIMONY

OF

SCOTT NORWOOD

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20200069-EI

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Scott Norwood. I am President of Norwood Energy Consulting, L.L.C. My business address is P.O. Box 30197, Austin, Texas 78755-3197.

Q. WHAT IS YOUR OCCUPATION?

A. I am an energy consultant specializing in the areas of electric utility regulation, resource planning and energy procurement.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have over 37 years of experience in the electric utility industry. After graduating from the University of Texas with a Bachelor of Science degree in electrical engineering, I began my career as a power plant engineer for the City of Austin's Electric Utility Department where I was responsible for electrical maintenance and design projects for the City's three gas-fired power plants. In January 1984, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Manager of Power Plant Engineering, and in that capacity was responsible for addressing resource planning, fuel and purchased power cost issues presented in regulatory filings before the PUCT. In 1986, I joined GDS Associates, Inc., an electric utility consulting firm, where I served as a Principal and Director of the firm's Deregulation Services Department for 18 years. In January 2004, I founded Norwood Energy Consulting, LLC, which is based in Austin, Texas. The focus of my current consulting practice is providing regulatory consulting and expert witness services to organizations representing consumers of electricity on matters related to electric utility economic, operational, and planning issues.[1]

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the Citizens of the State of Florida (Citizens) through the Office of Public Counsel ("OPC").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE UTILITY REGULATORY COMMISSIONS OR THE FLORIDA PUBLIC SERVICE COMMISSION ("FPSC" OR "COMMISSION")?

A. Yes, I have testified before both. I have filed testimony in over 200 electric utility regulatory proceedings involving electric restructuring, base rate, fuel recovery, power plant certification and demand-side management matters before state

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[1] *See*, Direct Exhibit SN-1 for a more detailed summary of my background and experience.

regulatory commissions in Arkansas, Alaska, Florida, Georgia, Illinois, Iowa, Kentucky, Louisiana, Michigan, Missouri, New Jersey, Ohio, Oklahoma, Texas, Virginia, Washington, and Wisconsin. I filed testimony on behalf of OPC in FPSC Docket No. 20130140-EI, a proceeding involving Gulf Power Company's application for approval of a transmission-related solution to an environmental compliance plan for the Company's coal-fired generating stations. That case was settled before hearing. I have also filed testimony addressing utility transmission and distribution grid hardening and grid modernization proposals and T&D reliability issues in regulatory proceedings over the last several years in Arkansas, Iowa, Oklahoma, Texas and Virginia.

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

A. The purpose of my testimony is to present my conclusions and recommendations regarding Duke Energy Florida, LLC's ("DEF" or "Company") application for approval of a Storm Protection Plan ("SPP" or "the Plan") for the ten-year period 2020-2029, pursuant to rule 25-6.030, F.A.C. ("SPP Rule").

Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR TESTIMONY?

A. Yes. I have prepared 15 exhibits which are included with my testimony.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS BASED ON YOUR REVIEW OF DEF'S SPP.

A. My testimony addresses the reasonableness of DEF's proposed SPP, which is expected to cost $6.6 billion over the next ten years, and $18.6 billion when fully deployed. The intended purpose of the SPP is to reduce outage time and restoration costs associated with "extreme weather events" ("EWE") through hardening of DEF's Transmission and Distribution (T&D) grid, undergrounding of distribution lines, and vegetation management programs.

My primary conclusions and recommendations regarding DEF's proposed SPP are as follows:

1) DEF's proposed SPP is expected to cost $6.6 billion over the next ten years and $18.6 billion once fully deployed. DEF has not provided details supporting its Cost/Benefit Analyses ("CBA") for the SPP; therefore, the claimed benefits and cost-effectiveness of the SPP cannot be verified. This lack of transparency in DEF's CBA calculations is highly unusual for an investment of this magnitude.

3) The estimated benefits included in DEF's CBA for the SPP are highly inflated by the assumption of EWE outage reduction levels that are more than double the historical average level of EWE outages, and by inclusion of non-electric customer avoided lost revenues.

4) DEF's CBA for the SPP did not evaluate potentially lower cost alternatives to the plan, such as delay or scaling back of the proposed $18.6 billion SPP.

5) DEF has provided high service reliability since 2006, with customers receiving service in 99.93% of all hours, including EWE outages. The forecasted improvement in reliability from the $6.6 billion SPP is relatively small, and would likely increase annual reliability by less than 0.05%.

6) While extreme weather events like major hurricanes have certain restoration and other costs that in theory could be mitigated, DEF has not adequately quantified these costs or demonstrated that it has an objective methodology to propose for properly conducting a CBA.

7) Given the very high cost of the SPP initiative, and the fact that the plan is not urgently needed in its current magnitude, it would be prudent for DEF to delay the Project (or portions of it) until the economic impacts of the COVID-19 pandemic are more certain.

Based on the above conclusions I recommend the Commission consider withholding approval of DEF's SPP, as proposed, pending the filing of an updated plan in 2022, so that an updated and meaningful CBA can be performed and an analysis of alternatives to the SPP can be conducted and comprehensive, longer-term COVID-19 impacts on Plan costs and implementation can be further evaluated.

III. SUMMARY OF DEF'S SPP APPLICATION

Q. PLEASE DESCRIBE DEF'S SERVICE AREA AND EXISTING TRANSMISSION AND DISTRIBUTION SYSTEM.

A. According to Duke Energy Corporation's 2019 Form 10K filing, DEF serves approximately 1.8 million retail electric customers located in a service area covering approximately 13,000 square miles located in North and Central Florida.[2] DEF has 29,400 miles of overhead facilities, including 5,200 miles of transmission lines, and approximately 24,200 miles of overhead distribution lines. The Company also has 18,200 miles of underground distribution lines, and 500 substations.[3]

Q. PLEASE DESCRIBE DEF'S PROPOSED SPP APPLICATION?

A. In 2019, the Florida Legislature enacted Section 366.96, Florida Statutes, ("SPP Statute") which requires Florida utilities to prepare and file 10-year Storm Protection Plans, at least every three years. The SPP Statute specifies that, among other things, utility SPP filings "must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability."[4]

As directed by the SPP Statute, the FPSC enacted rules to establish specific filing requirements and administrative procedures for review and approval of utility SPP filings and related cost recovery mechanisms. In this case, DEF is requesting Commission-approval of a SPP for the 10-year period 2020-2029, pursuant to FPSC Rule 25-6.030, F.A.C., (the "SPP Rule"), which establishes required elements of the

2 *See*, Duke Energy Corporation's 2019 SEC Form 10K filing, page 24.
3 *See*, Duke Energy Corporation's 2019 SEC Form 10K filing, page 35.

SPP filing, including descriptions of the Programs and specific projects and summaries of proposed costs for implementing the first three years of the SPP (2020-2021).

Q. DOES THE SPP STATUTE OR SPP RULE DEFINE THE TERM "EXTREME WEATHER EVENTS" ("EWE") AS APPLIED TO THE SPP?

A. No. However, the Company indicates that it has interpreted the term EWE to describe named tropical storms and Category 1 through 5 hurricanes, as defined by the Saffir Simpson scale.[5]

Q. WHAT IS THE TOTAL COST OF DEF'S PROPOSED SPP?

A. DEF proposes to expend approximately $6.6 billion over the 2020-2029 period for programs involving overhead hardening of T&D facilities, undergrounding of certain distribution lines, and enhanced vegetation management that it asserts are intended to reduce restoration costs and outage times to customers related to EWE.[6] DEF further indicates that it will take 20 to 30 years for certain of the proposed SPP programs to be fully deployed. As summarized in Table 1 below, the total estimated cost for full deployment of the SPP is approximately $18.6 billion, with approximately 82% of the total costs related to distribution system enhancements.

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4 Section 366.96(3), Florida Statutes.

5 *See*, Exhibit SN-2, DEF's response to OPC Interrogatory 3-96.

6 *See*, DEF witness Oliver's Direct Testimony, Exhibit JWO-4, pages 11-12.

Table 1

Estimated Deployment Cost of DEF's SPP Programs[7]

PROGRAM	Years to Deploy	10-YR Cost	Full Deployment Cost	% of Total Cost
Feeder Hardening	30	$1,573.0	$6,239.0	33.5%
Lateral Hardening	30	$2,266.0	$7,992.0	42.9%
Self Optimizing Grid	7	$561.0	$561.0	3.0%
Underground Flood Mitigation	20	$11.0	$26.0	0.1%
Distr Vegetation Management	3	$497.0	$497.0	2.7%
Trans Structure Hardening	30	$1,341.0	$2,671.0	14.3%
Substation Flood Mitigation	15	$27.0	$38.0	0.2%
Loop Radially Fed Substations	20	$52.0	$206.0	1.1%
Substation Hardening	20	$109.0	$199.0	1.1%
Trans Vegetation Management	1	$198.0	$198.0	1.1%
SPP Totals		$6,635.0	$18,627.0	100.0%
Total Distribution Programs		$4,908.0	$15,315.0	82.2%
Total Transmission Programs		$1,727.0	$3,312.0	17.8%

Q. IS THE SPP THE COMPANY'S FIRST MAJOR INITIATIVE TO REDUCE OUTAGE TIME AND OUTAGE RESTORATION COSTS RELATED TO MAJOR STORM EVENTS?

A. No. The SPP appears to be largely a continuation of DEF's filed Storm Hardening Plans ("SHP"), which have been submitted to the Commission every three years since 2007, pursuant to Commission Rule 25-6.0432. The Commission's rule describes the purpose of the SHP as follows:

> to ensure the provision of safe, adequate, and reliable transmission and distribution service for operational as well as emergency purposes; require the cost-effective strengthening of critical electric infrastructure to increase

7 Cost data for each SPP Program are derived from DEF witness Oliver's Direct Testimony Exhibit JWO-2, pages 8, 9, 14, 17, 19, 21, 29, 31, 33, 35, 36, 38 and 39.

> the ability of transmission and distribution facilities to withstand extreme weather conditions; and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions.

DEF's most recent SHP for the 2019-2021 period was submitted in March 2019 and approved by the Commission in July 2019.[8]

Q. HOW MUCH HAS DEF EXPENDED OR INVESTED TO HARDEN ITS SYSTEM AND REDUCE IMPACTS OF MAJOR STORMS UNDER PREVIOUS SHPS?

A. DEF indicates that it has expended or invested approximately $944 million in operation over the last five years for SHP projects, much of which includes grid hardening and vegetation management enhancements like the programs proposed in the current SPP.[9]

Q. HAVE DEF'S SHP EXPENDITURES SINCE 2007 BEEN EFFECTIVE IN REDUCING EXTREME WEATHER RESTORATION COSTS FOR ITS SYSTEM?

A. Although it seems probable that DEF's SHP investments have helped improve the resilience of DEF's T&D assets, it is difficult to estimate the extent to which these past expenditures reduced the duration and costs of extreme weather-related outages. This is because of the high variability of the intensity, duration, and paths of extreme weather events, and the fact that there have been relatively few EWEs on DEF's system over time.

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8 *See*, Oliver Direct Testimony, page 4.

Q. WHAT HAS BEEN THE FREQUENCY, DURATION AND COST OF PAST EWES THAT HAVE IMPACTED DEF'S SYSTEM?

A. DEF indicates it does not have records regarding EWE outage time or restoration costs that impacted its system before 2006.[10] However, since 2006 DEF's system has been impacted by approximately 4.4 EWEs per year, and these events resulted to outages to customers on average less than once every five years, while the average outage time from EWE events has been 218 minutes per year.[11]

Moreover, the averaged impact of EWE outages was heavily influenced by Hurricane Irma, an historically rare Category 4 hurricane that occurred in 2017. For example, DEF's annual average interruption times related to EWE for the 2006-2019 period would be approximately 44 minutes per year if the impacts of Hurricane Irma are excluded.[12] This 44 minutes per year average EWE outage time for DEF's system (excluding the impact of Hurricane Irma) is only <u>0.008%</u> (eight one thousandths of one percent) of total hours each year.

Q. WHAT ARE THE ESTIMATED COSTS OF PROGRAMS PROPOSED BY DEF IN ITS SPP?

A. DEF has proposed 10 programs to address EWE outage impacts under the SPP. The Company estimates that these programs will cost $6.6 billion over the next ten years and $18.6 billion after the SPP is fully deployed in approximately 30 years.[13] The

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9 *See*, Exhibit SN-3, DEF's responses to OPC Interrogatories 3-109 and 3-110.
10 *See*, Exhibit SN-4, DEF's response to OPC Interrogatory 3-98.
11 *See*, Exhibit SN-5.
12 *See*, Exhibit SN-5.
13 Cost data for each SPP Program are derived from DEF witness Oliver's Direct Testimony Exhibit JWO-2, pages 8, 9, 14, 17, 19, 21, 29, 31, 33, 35, 36, 38 and 39.

cost of proposed Distribution Feeder Hardening, Distribution Lateral Hardening, and Transmission Structure Hardening programs make up 78% of the total proposed SPP cost.

Q. HAVE ANY OF THE PROGRAMS IN DEF'S PROPOSED SPP BEEN DEPLOYED BY THE COMPANY AS PART OF PAST SHP'S?

A. Yes. In fact, most of the 10 proposed SPP programs have been deployed in some form by DEF as part of past SHP projects.

Q. WHAT ARE THE ESTIMATED REVENUE REQUIREMENTS FOR DEF'S PROPOSED SPP OVER THE TEN-YEAR PLAN PERIOD?

A. The total estimated revenue requirement of DEF's proposed SPP over the 2020-2029 plan period is approximately $2.9 billion.[14]

Q. WHAT IS THE ESTIMATED RATE IMPACT OF DEF'S PROPOSED SPP ON RESIDENTIAL CUSTOMERS?

A. DEF estimates that the proposed SPP investments will increase monthly electric charges to a residential customer who uses 1,000 kWh per month by approximately $0.27 per month in 2021, and by $1.22 per month in 2022.[15]

These DEF rate impact estimates are incremental rate impacts that exclude related costs of the SPP that have historically been recovered in base rates.

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14 Source is DEF witness Oliver's Direct Testimony Exhibit JWO-2, page 40.
15 Source is DEF witness Oliver's Direct Testimony, Exhibit JWO-2, page 40.

Q. HOW HAVE YOU EVALUATED THE REASONABLENESS OF DEF'S PROPOSED SPP?

A. My testimony focuses on three primary issues: 1) the extent to which DEF has demonstrated that the proposed SPP is cost-effective *and* represents the lowest reasonable cost alternative for reducing EWE outage durations and restoration costs; 2) the extent to which the SPP is needed and designed to reduce EWE outage time and outage restoration costs; and 3) whether the Commission should give its approval to the entire SPP as proposed for DEF to proceed with such a large project at a time when its customers are facing great economic uncertainty as a result of the COVID-19 pandemic.

IV. COST EFFECTIVENESS OF PROPOSED SPP

Q. HOW IS THE COST EFFECTIVENESS OF PROPOSED MAJOR UTILITY INVESTMENTS TYPICALLY EVALUATED IN REGULATORY PROCEEDINGS?

A. Once the need for an investment to ensure reliable electric service is established, the cost-effectiveness of the investment is typically evaluated through cost/benefit analyses, which are generally designed to determine whether projects are cost-effective, and the lowest reasonable cost alternative to supply the identified need, with due consideration given to uncertain major assumptions used for the analysis. The Legislature appears to have recognized this as they required the Commission to consider the estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan. Section 366.96(4)(c), Fla. Stat.

Q. HAS DEF PROVIDED A CBA THAT DEMONSTRATES THAT ITS SPP IS COST-EFFECTIVE AND THE LOWEST REASONABLE COST ALTERNATIVE TO REDUCE EWE OUTAGE TIME AND COSTS?

A. No; DEF has not presented a CBA that demonstrates that its SPP would be cost-effective or the lowest reasonable cost alternative to reduce outages and outage restoration costs related to EWEs. In my opinion, and as explained below, DEF has not presented an actual cost-benefit analysis in the true sense of what an analysis should contain.

Q. PLEASE EXPLAIN WHY DEF'S CBA DOES NOT DEMONSTRATE THAT ITS SPP WOULD BE COST EFFECTIVE AND THE LOWEST REASONABLE COST OPTION TO REDUCE EWE OUTAGE TIME AND COSTS.

A. There are three primary flaws in DEF's CBA for the SPP. First, the Company has not provided details regarding the CBA calculations for proposed SPP Programs, as required by FPSC Rule 25-6.030(3)(d), F.A.C. and Section 366.96(4), Fla. Stat.[16] While the Company has provided summary results for the total estimated costs and benefits of each proposed SPP Program, and a summary of major input assumptions, the failure of the Company to provide details as to how referenced benefits and costs were calculated for each SPP program, a breakdown of the total costs and benefits by type, or the calculations of the benefit/cost ratios for each proposed Program, prevents any party from verifying the CBA results. DEF has s only provided a

[16] *See*, Direct Exhibit SN-6, DEF's response to OPC Interrogatories 2-49 and 2-50 and OPC 2-23.

presentation of information and not an analysis of the information, which would require an explanation of how the information was developed. This lack of transparency and access to the details necessary to confirm the reasonableness of DEF's CBA for the $18.6 billion SPP is highly problematic, and based on my 35 years of regulatory consulting experience, extraordinary for a case involving approval of an investment of this magnitude.

The second major flaw in DEF's CBA for the SPP is that the Company's forecast of future EWE outage time is nearly 3 times the level of historical EWE outage since 2006. DEF has not provided a reasonable explanation for this variance, and the Storm Model used for this EWE forecast has not been used in any other regulatory proceeding and has not been benchmarked to demonstrate that it is accurately forecasting EWE outages for DEFs system. Notwithstanding the fact that DEF's forecast of EWE outage time is nearly 3 times its historical level over the last 14 years, the overall cost of the proposed SPP exceeds estimated benefits of the program unless untested, speculative and non-DEF-specific non-electric outage avoidance benefits are considered.

The third primary flaw in DEF's CBA for the SPP is that, although the Company considered scenarios that assumed higher outage time reduction and restoration cost benefits, it did not evaluate any alternatives to Programs included in its $18.6 billion Program.[17] For example, two plausible and potentially less costly alternatives to the SPP would be: 1) to delay the Plan for several years and continue with the Company's current practice under the SHP of strategically addressing worst performing circuits until there is a significant observed decline in T&D

reliability performance and then deploy the SPP, and 2) to significantly reduce the scale and investment level of the SPP by eliminating programs that are not cost-effective in recognition of the fact that the Company's EWE outage time over the last 14 years has been very low while overall service reliability (with EWE outages) has been very high compared to other utilities. However, the Company did not analyze these or other potentially lower cost alternatives to its proposed SPP.

The fourth primary flaw in DEF's CBA for the SPP is that it includes "non-electric customer benefits", which represent estimated customer avoided costs and lost revenues that are attributed to reduced EWE outage times. These non-electric customer benefits were calculated by DEF using the Interruption Cost Estimate Calculator ("ICE") software.[18] It is not appropriate to include such speculative non-electric benefits to justify a major electric utility investment such as the SPP. In fact, DEF admits it is not aware of any past case in which the Commission has approved major utility investments based on estimated customer lost revenues or customer savings that are not reflected on electric bills, such as DEF is proposing with inclusion of such non-electric customer benefits to support the SPP investments in this case.[19]

Q. ARE YOU ABLE TO DRAW ANY CONCLUSIONS REGARDING THE COST EFFECTIVENESS OF DEF'S PROPOSED SPP BASED ON THE LIMITED INFORMATION PROVIDED BY THE COMPANY ON ITS CBA?

17 *See*, Direct Exhibit SN-7, DEF's response to OPC Interrogatory 8-251.
18 *See*, DEF witness Oliver's Direct Testimony, Exhibit JWO-4, page 27.
19 *See,* Direct Exhibit SN-8, DEF's responses to OPC Interrogatories 3-116 and 3-117

A. Yes. Although DEF has not provided details of its CBA calculations, from the information obtained through discovery, I have concluded that the Company's estimate of SPP Program benefits is greatly inflated due to DEF's inflated EWE outage forecast, and the improper inclusion of non-electric customer avoided costs and lost revenues, as a component of SPP benefits. If these two primary flaws in DEF's CBA are corrected, the cost of the proposed SPP is several times higher than the estimated benefits of the Plan.

Q. PLEASE DESCRIBE THESE TWO FLAWS IN DEF'S CBA IN MORE DETAIL?

A. DEF's CBA includes more than $35 billion in estimated non-electric customer benefits.[20] While I agree that DEF's customers may realize certain non-electric cost savings and revenue benefits if the SPP reduces EWE outage times, such benefits are difficult to quantify or verify, are not components of DEF's electric cost of service, and certainly do not come close to meeting the "known and measurable" standard that has traditionally been applied by most regulatory commissions in determining costs that may be recovered through electric utility rates.

As summarized in Table 2 below, when these non-electric customer benefits are removed from the SPP CBA, only one of the proposed SPP programs – the Underground Flood Mitigation Program - is forecasted to provided electric benefits that justify the forecasted cost of deploying the program.

20 *See*, Exhibit SN-9.

Table 2

DEF CBA Results Excluding Non-Electric Customer Benefits[21]

($Millions)

SPP Program	Life Cost	Electric Benefits	Net Electric Benefit/Cost	Electric Benefit/Cost
Feeder Hardening	$1,537.1	$377.2	($1,159.9)	0.25
Lateral Hardening	$1,810.3	$1,207.9	($602.4)	0.67
Self Optimizing Grid	$255.6	$0.0	($255.6)	0.00
Underground Flood Mitigation	$10.8	$16.0	$5.2	1.48
Distr Vegetation Management	$497.0	$0.0	($497.0)	0.00
Trans Structure Hardening	$1,298.9	$791.8	($507.1)	0.61
Substation Flood Mitigation	$29.6	$6.9	($22.7)	0.23
Loop Radially Fed Substations	$58.0	$0.7	($57.3)	0.01
Substation Hardening	$103.4	$7.0	($96.4)	0.07
Trans Vegetation Management	$198.0	$0.0	($198.0)	0.00
SPP Totals	$5,798.7	$2,407.5	($3,391.2)	0.42
Total Distribution Programs	$4,110.8	$1,601.1	($2,509.7)	0.39
Total Transmission Programs	$1,687.9	$806.4	($881.5)	0.48

Note: Distribution Programs evaluated over 30 years; Transmission programs evaluated over 40 years.

The second major flaw relates to DEF's apparent overstatement of future EWE outage minutes. DEF's actual EWE outage impact on average customer outage time (SAIDI) over the 2006-2019 period was approximately 214 minutes per year, and Hurricane Irma represented approximately 81% of the total EWE outage minutes during this period.[22] In fact, DEF's analysis of historical hurricane events over the last 200 years indicates that the expected frequency for a Category 4 hurricane impacting the DEF service area is approximately 0.0016 events per year. [23] If the extraordinarily rare impact of Hurricane Irma is excluded, DEF's average EWE outage SAIDI impact over the last 14 years drops to approximately 44

21 *See*, Exhibit SN-10.
22 *See*, Direct Exhibit SN-5.
23 *See*, Direct Exhibit SN-11, DEF's response to OPC Interrogatory 8-249.

minutes per customer per year.[24] This 44 minute EWE SAIDI impact represents only 0.008% of the total time in a year.

In contrast, DEF's CBA analysis for the SPP uses a forecasted EWE outage SAIDI impact of approximately 622 minutes per year. This EWE outage time forecast is 2.9 times the Company's historical average EWE outage time impact with Hurricane Irma and 14.2 times the average EWE outage time without Irma. DEF provided no reasonable support for the exaggerated 622 minute per year forecasted EWE SAIDI impact numbers.

The effect of DEF's distorted EWE outage time forecast is that it serves to greatly inflate the forecasted SPP outage reduction benefits in the Company's CBA. For example, the Company's CBA assumes that the SPP will *reduce* EWE outage time by 533.5 million minutes, which is 1.4 times more than DEF's average EWE outage time per year (including Irma) on its system over the last 14 years (385 million minutes per year). By unreasonably skewing the outage reduction benefit of the SPP, DEF's CBA further overstates the electric cost benefits of the SPP presented in Table 2 above.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COST-EFFECTIVENESS OF DEF'S PROPOSED SPP?

A. DEF has not provided details necessary to verify the reasonableness of the high-level CBA summary results it has provided for its SPP. Moreover, DEF has not shown that the rate impacts are justified or affordable, under the emerging economic conditions of the COVID-19 pandemic. From the limited information that was

24 *See*, Direct Exhibit SN-5.

provided by DEF, it is apparent that the Company's CBA analysis includes greatly overstated benefits estimates due to its unrealistically high forecast of EWE outage time that would occur without the SPP, and the inclusion of difficult to verify non-electric customer benefits that are not known and measurable, and for which the Commission should be cautious about giving too much weight or credence without more evidence of the reliability of the information and the relationship to the circumstances of DEF's customers when deciding recovery for any major utility investment. Moreover, the Company's CBA for the SPP did not evaluate any potentially lower cost alternatives to the Plan, and includes only one Program that is forecasted to produce net electric cost savings to customers. Given these facts, it would be imprudent for DEF to proceed with the proposed $18.6 billion SPP initiative, particularly when the Company already has very high T&D service reliability and with the uncertainty that presently exists due to the COVID-19 pandemic.

V. NEED FOR PROPOSED SPP

Q. HOW IS THE NEED FOR MAJOR T&D RELIABILITY INVESTMENTS GENERALLY MEASURED?

A. Electric T&D service reliability is most commonly measured by two performance metrics: 1) the System Average Interruption Frequency Index ("SAIFI"), which represents the average number of outages per customer per year; and 2) the System Average Interruption Duration Index ("SAIDI"), which is the average duration of T&D outages per customer per year, expressed in minutes. Often these two reliability metrics are reported with and without the impacts of extreme weather events, such as hurricanes or tornados, which cause impacts that are difficult to control. In fact, the Commission's rules require that DEF and other utilities file Annual Distribution Reliability Reports each year, and specify that reliability data be provided with and without adjustments to remove impacts of EWEs.[25]

Q. HAS DEF'S T&D RELIABILITY PERFORMANCE BEEN REASONABLE OVER THE LAST TEN YEARS?

A. Yes. While I have not examined the performance of each of DEF's T&D circuits, overall, the Company's service reliability has been very good over the last ten years. For example, as summarized in Table 3 below, DEF's customers have experienced approximately 1.39 outages per year and approximately 390 minutes per year of service interruption including impacts of EWEs. If the impact of the extraordinary Hurricane Irma is excluded, DEF's average SAIDI including EWEs drops to approximately 150 minutes per customer per year over the last ten years.

25 *See*, FPSC Rule 25-6.0455, Annual Distribution Service Reliability Report.

Table 3

DEF's Distribution System Reliability Performance[26]

	SAIDI (Outage Minutes) Incl EWE	SAIDI (Outage Minutes) Excl EWE	SAIDI (Outage Minutes) w EWE,Excl Irma
2010	104.70	102.20	104.70
2011	162.10	97.80	162.10
2012	126.70	79.70	126.70
2013	97.80	95.40	97.80
2014	93.90	93.50	93.90
2015	88.00	87.90	88.00
2016	355.60	93.50	355.60
2017	2,553.10	92.90	0.00
2018	215.60	110.30	215.60
2019	101.90	98.80	101.90
:010-19 Average	389.94	95.20	134.63
Avg Reliability	**99.93%**	**99.98%**	**99.97%**

Q. WHAT DO THE DATA IN TABLE 3 ABOVE INDICATE REGARDING DEF'S SERVICE RELIABILITY?

A. This performance means that over the last 10 years on average, DEF's customers have received electric service in 99.93% of the hours each year, including impacts of major storm events (with Irma), 99.97% of all hours including EWE outages and excluding Irma, and in 99.98% of all hours when EWE outages are excluded. This past performance of DEF's system represents high service reliability, whether or not EWEs and Irma are considered.

[26] *See*, Exhibit SN-12, DEF's responses to OPC Interrogatories 2-46 and 2-47.

Q. HOW DOES DEF'S 99.93% SERVICE RELIABILITY INCLUDING EWE'S COMPARE TO THE RELIABILITY PROVIDED BY OTHER INVESTOR-OWNED ELECTRIC UTILITIES?

A. DEF's T&D reliability performance falls within the top quartile of performance for all similarly sized investor-owned utilities in the United States, and also compares favorably to the SAIDI performance of other Florida electric utilities.[27]

In summary, DEF's historical T&D service reliability including impacts of EWE outages has been high and better than most investor-owned utilities within Florida and the United States; therefore, the Commission should require more analysis and justification – including the CBA and lower cost alternatives discussed earlier in my testimony – before taking final action to approve all or part of the Company's proposed $6.6 billion investment for the SPP over the next ten years.

Q. IS THERE EVIDENCE THAT DEF'S CUSTOMERS ARE DISSATISFIED WITH THE COMPANY'S RELIABILITY PEFORMANCE?

A. There is evidence that DEF customers are not dissatisfied. As summarized in Table 4 below, over the last ten years DEF has averaged 83.5 complaints per year regarding the reliability of service it provides, which represents approximately 0.005% of the Company's 1.8 million customers.

Table 4

DEF Customer Complaints

Related to T&D Reliability Issues[28]

	Complaints	% Total Customers
2010	95.0	0.005%
2011	79.0	0.004%
2012	58.0	0.003%
2013	84.0	0.005%
2014	90.0	0.005%
2015	68.0	0.004%
2016	64.0	0.004%
2017	82.0	0.005%
2018	120.0	0.007%
2019	95.0	0.005%
AVG:	83.5	0.005%

Q. ARE THEIR OTHER INDICATORS OF THE LEVEL OF SATISFACTION AND ACCEPTANCE OF THE LEVEL OF SERVICE RELIABILITY?

A. Yes; the Company offers a premium distribution service (PDS) option on all non-residential tariffs per section 2.05 of the Company's General Rules and Regulations Governing Electric Service.[29] However, since 2015 approximately only 30 of DEF's 1.8 million customers have purchased electricity under this optional tariff, which indicates broad customer acceptance of DEF's current service reliability or perhaps the lack of interest by most customers to pay more for higher service reliability.

Q. WOULD DEF'S T&D RELIABILITY BE GREATLY IMPROVED IF THE SPP IS IMPLEMENTED?

27 *See*, Exhibit SN-13, 2018 EIA 861 Distribution Reliability Survey data.
28 *See*, Exhibit SN-14, DEF's response to OPC's Interrogatory 3-122.
29 *See*, Exhibit SN-15, DEF's response to OPC's POD 2-22.

A. It could be improved; however, the question is at what price are the relatively minor achievable gains cost effective. As discussed earlier in my testimony, DEF has averaged approximately 44 minutes per year of EWE-related outage time since 2006, if impacts of Hurricane Irma are excluded. I understand that the Legislature determined that it is in the interest of the state to increase resilience and reliability. They appear to have been aware that the Company has or will have expended close to a billion dollars since 2006 on SHP programs to harden its T&D grid and for enhanced vegetation management programs to reduce outages and storm restoration costs. For this reason, it is important to note that in Sections 366.96(3) and (4)(a) – (d), Fla. Stat., the Legislature required that the utilities explain the "systematic approach" they will "follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." The Legislature further required the Commission to consider ***the extent to which*** the plan is expected to reduce restoration costs and outage times associated with extreme weather and enhance reliability, including whether the plan prioritizes areas of lower reliability performance. They also ***required*** that the Commission consider the costs and benefits of making the improvements proposed in the plan and the rate impacts.

In other words, the Legislature stated rather plainly that there is no presumption that a utility's proposed plan would be approved. Rather, it laid out tests of demonstration that objectives would be achieved and those would be cost effective with an eye towards the impact on those who have to pay the costs. In this regard, one of the fundamental concerns that I have is illustrated under the circumstance where, assuming that future EWE outages remain at the average 44 minute level reported since 2006, and that the Company was able to eliminate all EWE outage time through deployment of the SPP (which is not likely), the improvement in DEF's reliability would only be approximately 0.008%, from the 99.93% reliability level including EWE outages over the last ten "no SPP" years to a level of 99.94% with the SPP. Even if DEF guaranteed this very small improvement in reliability, which it has not, such a small improvement in reliability would not seem to justify the rate impact of the $6.6 billion DEF proposes to spend to deploy the SPP over the next 10 years under circumstances that may be clouded by the very real and affordability-threatening economic fallout of the COVID-19 pandemic. I also contend that given these circumstances, it is far too early for the Commission to give any level of approval to the entire $18.6 billion the Company expects to spend over the next 30 years to fully deploy the SPP.

In summary, DEF's forecast that the $18.6 billion SPP initiative could be justified by the reduction in EWE outage time on its system is highly suspect given the high level of reliability of DEF's system (99.93% including EWEs) that has been achieved without the SPP, and the relatively small level of EWE outage time experienced by the Company's customers since 2006, except during Hurricane Irma, which was a rare Category 4 event that is not expected to be repeated soon.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AS TO WHETHER THE SPP IS COST-EFFECTIVE AND NEEDED TO IMPROVE DEF'S T&D SERVICE RELIABILITY.

A. The SPP is not likely to materially improve DEF's T&D service reliability. DEF has provided highly reliable T&D service for at least the last ten years and is on a trajectory to provide highly reliable service as a result of the Company's significant past and ongoing expenditures and investments for Grid Hardening and Vegetation Management since the Company's SHPs were initially implemented in 2006. There is evidence that most of DEF's customers are not dissatisfied with DEF's existing reliability service given the relatively small level of complaints filed related to service reliability and the general lack of customer interest in paying more for DEFs optional premium service tariff, which provides higher than standard reliability for a price. Moreover, the improvement in reliability performance that DEF claims would result from the SPP project is not guaranteed and has not been shown to be cost-effective as I discussed earlier in my testimony.

VI. <u>ECONOMIC IMPACTS OF COVID-19 PANDEMIC</u>

Q. SHOULD THE COMMISSION CONSIDER POTENTIAL ECONOMIC IMPACTS OF THE COVID-19 PANDEMIC IN DECIDING WHETHER DEF'S PROPOSED $18.6 BILLION SPP PROJECT SHOULD GO FORWARD AT THIS TIME?

A. Yes. The COVID-19 pandemic has already had tremendous adverse impacts on the U.S. and World economies as a result of widespread public health effects, travel restrictions, job loss and forced shutdown of many businesses. Although we are very early in the pandemic, and Florida has been affected less than many other states, the final economic impacts and effects on Florida, its citizens and the electric utility industry as a whole remain uncertain. Given this situation, I recommend that the Commission require DEF to update its SPP on April 1, 2022 for COVID-19 impacts, including affordability and other downstream cost impacts driven by the related economic fallout. This update would accompany the robust CBA that I point out is lacking in this filing and would also give the Commission more visibility into any affordability impacts that come to light after the base rate increase case that DEF is expected to file in early 2021. It would be prudent for the Commission at this time to delay full consideration of the proposed $18.6 billion SPP until potential impacts of COVID-19 on DEF's customers are more certain, particularly when it appears that there is no urgent need or demand for the very small projected reliability benefits that the Plan might provide.

Q. HAS THE COMMISSION RECOGNIZED THE NEED TO CONSIDER SPECIAL REGULATORY RELIEF TO MITIGATE ECONOMIC IMPACTS OF COVID-19 TO CUSTOMERS?

A. Yes. While it is in the early stages of this process, it is my understanding that the Commission has recently adopted proposals that would accelerate fuel cost refunds to customers in an effort to mitigate the economic impacts of COVID-19. I am also aware that in a different docket, the Commission's staff has asked for DEF to update assumptions and impacts of a large nuclear decommissioning and dismantlement proposal based on COVID-19 effects.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT DO YOU CONCLUDE ABOUT THE COMBINATION OF THE LACK OF A CBA, THE APPARENT MINIMAL OR NON-EXISTENT NEED FOR THE ENTIRE SPP AS FILED AND THE LOOMING IMPACT OF COVID-10 ON THE SPP?

A. Because of the interplay and impact of all these factors, the Commission should be cautious in giving wholesale approval in today's environment to DEF's proposed $18.6 billion SPP initiative at this time. It is my understanding that Section 366.96(5), Fla. Stat., gives the Commission three options when confronted with a plan. It can approve the SPP as filed. It can reject the Plan. It can approve the SPP with modification. Under the circumstances of this case, where DEF has failed to file details necessary to verify the summary results provided for the Company's SPP CBA, and with the $6.6 billion price tag for the first 10 years along with the uncertainties associated with COVID-19 being unresolved and poorly understood, the Commission should proceed cautiously. While I do not believe that the Commission should endorse the Plan as filed, given that the Florida Legislature expected that utilities would implement cost effective plans that would enhance reliability and resilience of the grid, it seems like the third option of approving the plan with modifications appears to be the best option.

Given that the Legislature also required the Commission to determine the rate impacts of the three-year horizon of each plan, in conjunction with its disposition of the plans, it is apparent that the Legislature was concerned about customer rate impacts and that affordability of SPP implementation must be considered. To this end, I am recommending that the Commission temper any approval of the DEF Plan in these highly uncertain times, with a requirement that the Company submit a Plan update by April 1, 2022 that includes a cost benefit analysis with a true analysis with a complete and detailed demonstration of how the relevant costs and benefits are calculated. In addition, the Commission should require the Company to provide a full and complete discussion of how the long-term effects of the COVID-19 pandemic – including any severe economic ramifications – are expected to impact the affordability of electric service. This analysis should address how the costs of implementing the SPP may be impacted by COVID-19, including the extent to which cost inputs such as fuel prices, labor costs and labor working conditions, electricity sales growth rates, and other societal impacts of COVID-19 are reflected in the CBA supporting the SPP.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS REGARDING DEF'S PROPOSED SPP?

A. My primary conclusions regarding DEF's proposed SPP initiative are as follows:

1) DEF's proposed SPP is expected to cost $6.6 billion over the next ten years and $18.6 billion once fully deployed. DEF has not provided details supporting its Cost/Benefit Analyses for the SPP; therefore, the claimed benefits and cost-effectiveness of the SPP cannot be verified. This lack of transparency in DEF's CBA calculations is highly unusual for an investment of this magnitude.

3) The estimated benefits included in DEF's CBA for the SPP are highly inflated by the assumption of distorted EWE outage reduction levels that are more

than double the historical average level of EWE outages, and by inclusion of non-electric customer avoided lost revenues.

4) DEF's CBA for the SPP did not evaluate potentially lower cost alternatives to the plan, such as delay or scaling back of the proposed $18.6 billion SPP.

5) DEF has provided high service reliability since 2006, with customers receiving service in 99.93% of all hours, including EWE outages. The forecasted improvement in reliability from the $6.6 billion SPP is relatively small, and would likely increase annual reliability by less than 0.05%.

6) Given the very high cost of the SPP initiative, and the fact that the plan is not urgently needed in its current magnitude, it would be prudent for DEF to delay the Plan until the economic impacts of the COVID-19 pandemic are more certain, and so that potentially less costly alternatives to the SPP can be evaluated.

Based on the above conclusions, and the fact that DEF recently committed to spend approximately $688 million over the next three years for similar grid hardening programs under the Company's 2019-2021 SHP, I recommend the Commission consider withholding full approval beyond year 2021 of DEF's proposed SPP pending the filing of an updated plan in 2022, so that analysis of alternatives to the SPP can be conducted and longer-term COVID-19 impacts on Plan costs and implementation can be further evaluated.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

(Whereupon, prefiled direct testimony of Lane Kollen was inserted.)

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 University. 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 DO YOU PROVIDE TESTIMONY?

A. I provide 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 Tampa Electric Company's ("TECO" or "Company") proposed Storm Protection Plan ("SPP") and the effects of ratemaking principles and recovery of the SPP project costs[2] as important factors in the framework of the SPP, the scope of the SPP projects, the selection of the SPP projects, and the effects that these factors will have on the recovery of the SPP project costs in the Company's subsequent SPP Cost Recovery Clause ("SPPCRC") proceeding. My testimony should be considered in conjunction with the testimony of Mr. Scott Norwood on behalf of OPC.

C. Summary of The Company's Request

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST.

A. The Company plans to spend $1,921 million on its proposed SPP projects over the ten-year life of the SPP plan. The Company proposes revenue requirements of $972 million that it will likely seek to recover through the SPPCRC over that same ten-year period. The

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

[2] The term "project costs" refers to both project costs and program costs interchangeably, depending on the level of detail available.

Company's proposed annual spend and related revenue requirement amounts are shown in the following tables.[3]

SPP Costs by Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Capital Total	$29.42	$122.61	$168.88	$168.06	$176.10	$186.04	$181.56	$181.19	$189.69	$185.26	$1,588.80
O&M Toal	$23.70	$28.03	$29.47	$32.75	$32.35	$34.17	$35.35	$36.78	$38.76	$40.48	$331.85
Overall Total	$53.12	$150.64	$198.35	$200.81	$208.45	$220.21	$216.91	$217.98	$228.45	$225.75	$1,920.66

SPP Revenue Requirements by Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Capital Total	$0.73	$8.71	$22.74	$38.71	$54.58	$71.08	$87.42	$103.13	$118.83	$134.37	$640.31
O&M Toal	$23.70	$28.03	$29.47	$32.75	$32.35	$34.17	$35.35	$36.78	$38.76	$40.48	$331.85
Overall Total	$24.43	$36.74	$52.21	$71.46	$86.93	$105.25	$122.77	$139.92	$157.60	$174.85	$972.16

Q. HOW DO THE TOTAL SPEND AND REVENUE REQUIREMENTS COMPARE TO TECO'S PRESENT TOTAL NET PLANT AND REVENUES?

A. The Company's net plant in-service at December 31, 2019, was $6,496 million.[4] The proposed SPP capital spend will increase net plant by $1,589 million in 2029, or 24.5%, all else equal. The Company's total revenues in 2019 were $2,007 million.[5] The proposed SPP annual revenue requirement will be $175 million in 2029, or an increase of 8.7% on average over all customer classes, all else equal.[6] TECO estimates that the increases for the residential class will be much greater than the increases for the commercial and industrial classes.[7]

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

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

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[3] Response to OPC POD No. 15 (tab Summary Data from Excel file (BS 93) Master – Charts 1 included in Tables folder). *See also* Exhibit No. ASL-1 attached to the Direct Testimony of A. Sloane Lewis for the annual revenue requirements by SPP program.

[4] Tampa Electric Company FERC Form 1 at 110.

[5] *Id.* at 114.

[6] As explained in more detail in footnotes 7 and 8, below, these amounts do not reflect offsets for reductions in base rates or Storm Hardening Plan ("SHP") rates.

[7] Direct Testimony of A. Sloan Lewis at 9.

A. The Company's proposed SPP total spend, increase in rate base, and increase in customer rates are significant. These are incremental costs with incremental customer rate impacts. The framework, scope, and selection of the SPP projects will be determined in this proceeding, not the subsequent SPPCRC proceeding. Therefore, the ratemaking principles and recovery of the SPP project costs are important factors in the decision process in this proceeding.

To qualify for selection in the SPP proceedings and cost recovery in the SPPCRC proceedings, the projects and the costs of the projects must be prudent, used and useful, and just and reasonable. These factors must be considered in the decision process in the SPP proceedings, not limited to the review after the projects are selected and costs are incurred that will take place in the SPPCRC proceedings.

In addition, the total multi-year customer rate impact can be considered only in the SPP proceeding; they will not be addressed in the SPPCRC proceedings. The SPPCRC proceedings will address the actual recovery and annual customer rate impact only after the decision process in this proceeding is complete, projects are approved, and the SPP is 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 its filing, the Company did not, with limited exceptions, explicitly exclude the costs presently recovered in base rates or expressly account for any avoided cost savings.[8,9] The Company will retain the avoided cost savings for costs presently recovered in base rates unless these costs are addressed in this proceeding or otherwise included in a negotiated resolution.

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

I recommend that the Commission rely solely on an estimate of the avoided costs in quantifying the benefits (savings) and the benefit-to-cost ratios of the SPP projects.

I recommend that the Commission reject the Company's use of value-of-service benefits in the quantification of benefits in order to economically justify the proposed SPP projects. Value-of-service benefits are unknown, subjective, cannot objectively be measured, are not actually incurred, and cannot be avoided, except, perhaps, in an abstract conceptual framework untethered to actual customer rates.

[8] After TECO made the filing, the Company, OPC, and other parties entered into a settlement agreement dated April 27, 2020, wherein they agreed that certain costs would be removed from base rates through a base rate reduction and included in the SPPCRC when the SPPCRC is implemented. Upon approval by the PSC, this issue will have been resolved. As noted in footnote 9, TECO has provided the proposed SPP revenue requirement with and without the effect of the settlement agreement.

[9] Response to OPC POD No. 13. The response includes an Excel file that compares the proposed SPP revenue requirement before and after the settlement agreement.

II. APPLICATION OF RATEMAKING STANDARDS AND RECOVERY TO THE FRAMEWORK OF THE SPP, SCOPE OF THE SPP PROJECTS, AND SELECTION OF SPP PROJECTS

Q. DESCRIBE HOW THE APPLICATION OF RATEMAKING STANDARDS AND RECOVERY AFFECTS THE FRAMEWORK OF THE SPP, THE SCOPE OF THE SPP PROJECTS, AND THE SELECTION OF SPP PROJECTS.

A. Rules 25-6.030 and 25-6.031, F.A.C., establish a required framework for the utility's SPP, including the utility's identification of projects that will reduce outage times and outage restoration costs, provide an estimate of the customer rate impacts, and establish the 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 Rules provide important customer safeguards that require the utility to justify the SPP projects and costs, ensure that there is a comparison of benefits to costs, and ensure that the utility only recovers incremental costs net of avoided costs (reductions in costs, or savings, regardless of whether those costs are recovered in base rates or recovery clauses) through the SPPCRC.

More specifically, Rule 25-6.030 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. 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 establish 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.

Rule 25-6.031 requires that costs included in the SPPCRC be "prudent" and "reasonable." Although these requirements are found in this Rule, the determination of whether the costs included in the SPPCRC are prudent and reasonable presupposes that the SPP programs and projects approved in the SPP docket were prudent and that the estimated costs of the programs and projects were reasonable. The sequential nature of these determinations effectively limits the 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.

Rule 25-6.031 also limits the costs eligible for recovery through the SPPCRC to incremental costs net of avoided costs (savings). It specifically requires the exclusion of costs that are recovered through base rates and other clause forms of ratemaking recovery.

Q. ARE THE TWO RULES INTERRELATED?

A. Yes. Certain ratemaking determinations required pursuant to Rule 25-6.031 necessarily start with an assessment of the projects that can only be performed in the SPP proceeding and then confirmed or refined in the SPPCRC proceeding.

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

Q. WHY IS AN ECONOMIC JUSTIFICATION NECESSARY FOR THE SPP PROJECTS?

A. Fundamentally, the SPP itself and the SPP programs and projects are incremental (above and beyond the present scope and costs for actual and planned capital expenditures and O&M expenses), with the exception of the existing vegetation management programs and projects, which also were included in the SPP. In addition, the scope of the SPP and the selection of the new SPP projects are discretionary. They should be authorized only if the benefits exceed the costs; in other words, the benefit-to-cost ratio should be at least 100%. By its terms, Rule 25-6.030 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." The proposed SPP programs and projects are incremental, with the exception of the existing vegetation management programs and projects; they were not necessary and still are not necessary for reliable utility service at the least practicable cost. If the projects had been necessary 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.

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

Third, 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.

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 new assets that require less maintenance than the assets that were replaced and the future savings due to near-term accelerated and enhanced vegetation management activities and expense.

Q. IS THAT HOW THE COMPANY MEASURED THE BENEFITS OF ITS PROPOSED PROJECTS?

A. No. The Company added the savings in outage restoration costs estimated by 1898 & Co., calculated using its proprietary models over a range of extreme weather events and range of damage and outage conditions, to the "value of service" to its customers based on surveys and other sources of estimates for such values.[10] Even including the arguable

[10] 1898 & Co. refers to the "value of service" as the monetization of customer minutes of interruption ("CMI").

value-of-service benefits, none of the Company's projects were economically justified with a benefit-to-cost ratio of at least 100%.

The following table summarizes the benefit to cost ratios for the Company's proposed SPP projects based on 1898 & Co.'s definition of benefits, which range from 10% to 90%.[11] None of the SPP program categories show benefits that equal (100%) or exceed the costs of the programs (more than 100%), even if the "value of service" to its customers is included in the calculation of the benefits. The SPP programs with the lowest benefits-to-cost ratios are the proposed transmission access improvements program (10%) and the proposed increases in vegetation management activities and expense (21%).

Tampa Electric - Proposed 2020-2029 Storm Protection Plan
Projected Costs versus Benefits

Storm Protection Program	Projected Costs (in Millions)		Projected Reduction in Restoration Costs (Approximate Benefits in Percent)	Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent)	Program Start Date	Program End Date
	Capital	O&M				
Distribution Lateral Undergrounding	$976.8	$0.0	34	44	Q2 2020	After 2029
Vegetation Management	$0.0	$279.3	21	22 to 29	Q2 2020	After 2029
Transmission Asset Upgrades	$149.1	$3.0	90	28	Q2 2020	2029
Substation Extreme Weather	$32.4	$0.0	70 to 80	50 to 65	Q1 2021	After 2029
Distribution Overhead Feeder	$289.7	$8.9	40 to 44	32	Q2 2020	After 2029
Transmission Access Enhancements	$14.8	$0.0	10	74	Q1 2021	After 2029

[11] Tampa Electric's 2020-2029 Storm Protection Plan filed on April 10, 2020 (table at 72 in Exhibit GRC-1 attached to the Direct Testimony of Mr. Chasse, along with supporting charts and calculations provided in response to OPC POD No. 15).

Q. IF THE SPP PROGRAMS ARE NOT ECONOMICALLY JUSTIFIED, CAN THE COSTS BE JUST AND REASONABLE?

A. No. If the costs are not economically justified, then the costs ordinarily would not be incurred. If they are incurred, absent a Commission directive, prior approval, or other legal requirement, then they are imprudent and are not just and reasonable. Mr. Norwood also addresses the economic justification threshold and the 1898 & Co. calculation of incremental benefits based on the "value of service" to its customers.

Q. WHY IS THE REQUIREMENT IN RULE 25-6.030, F.A.C., TO PROVIDE THE ESTIMATED ANNUAL CUSTOMER RATE IMPACT AN IMPORTANT CONSIDERATION IN THIS SPP PROCEEDING?

A. If the expected value of the incremental savings does not exceed the estimated total cost, as measured by the incremental revenue requirement, then the SPP programs and projects are not economically justified and should not be approved. The customer rate impact is the estimated incremental annual cost that the Company's customers will pay for the SPP projects over the life of the SPP before offset for any potential savings, which include estimates of known savings in recurring annual costs as well as estimates of unknown savings that ultimately will depend on the actual effects of any future extreme weather events.

Of course, the customer rate impact will extend well beyond the ten-year life of the Company's SPP. The return of and on the capitalized project costs will continue for the lives of the SPP projects, potentially 30 to 50 years beyond the ten-year life of the Company's SPP. The expense projects will continue indefinitely to the extent that TECO continues to incur the incremental expenses beyond the ten-year life of the SPP.

Q. DID TECO PROPERLY CALCULATE THE ANNUAL CUSTOMER RATE IMPACT?

A. No. The Company provided an estimate of the incremental customer rate impact for the ten-year life of the SPP based on the sum of the return of and on the incremental capitalized cost and the incremental expenses. The Company calculated the total customer rate impact as $972.165 million over the ten-year life of the SPP.[12]

TECO failed to include additional savings related to "normal operation" and "normal weather," which it refers to as "blue sky days," except for the savings in vegetation management expense it claims is reflected in the Accenture analysis and quantifications.[13]

Mr. Chasse acknowledged that the SPP projects would achieve further benefits in day-to-day operations.[14]

> These analyses demonstrate there are significant benefits associated with these Programs including reduced restoration costs, reduced outages, and reduced restoration times. Further Program benefits will accrue in day-to-day operations.

If these additional savings are not accounted for in this SPP and the SPPCRC proceeding or otherwise included in a negotiated resolution, then the Company would retain the savings in costs that presently are recovered in base rates. The Company's

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[12] Tampa Electric's 2020-2029 Storm Protection Plan filed on April 10, 2020 (table at 74 in Exhibit GRC-1 attached to the Direct Testimony of Mr. Chasse, along with supporting calculations provided in response to OPC POD No. 13). The Company calculated the revenue requirements that sum to this amount without the effects of the subsequent settlement between the Company and OPC. The settlement removed the capital-related and expense effects of the distribution pole replacements and expense effects of unplanned transmission and distribution vegetation management from the SPPCRC, and added expense effects of planned transmission and distribution vegetation management and certain other expenses presently recovered through base rates to the SPPCRC.

[13] Responses to OPC POD No. 27 and OPC IRR No. 53. I have attached these responses as my Exhibit LK-2.

[14] Direct Testimony of Gerard Chasse at 26.

internal accounting guidelines do not require that these additional savings be tracked or used as an offset to reduce the amounts recovered through the SPPCRC.[15]

In addition, the Company did not recognize the additional savings due to increases in cost-free accumulated deferred income taxes ("ADIT") capital related to the retirement of plant in service recovered in base rates and did not reflect any savings due to ADIT in its calculation of the estimated annual revenue requirements for the SPPCRC.[16] Unless these effects are intended to be recognized in the settlement between the Company, OPC, and other intervening parties, the omissions could overstate the costs recovered in the SPPCRC.

Q. IF THE COMMISSION IS INCLINED TO APPROVE THE SPP PROGRAMS AND PROJECTS THAT DO NOT HAVE BENEFIT TO COST RATIOS OF AT LEAST 100%, DO YOU HAVE ANY RECOMMENDATIONS?

A. Yes. The Commission should seek to minimize the customer impact (harm) of such SPP programs and projects. It could do so by limiting the SPP programs and projects to those with benefit-to-cost ratios of no less than a defined threshold, such as 50%. Although not an approach that I recommend, it nevertheless would establish a cutoff to allow projects with greater benefits to customers compared to costs, but disqualify those projects with lesser benefits to customers compared to costs. It also could do so by limiting the rate

[15] Response to OPC POD No. 13. I have attached an excerpt (narrative response plus document entitled "Guidance for Charging to the SPPCRC") as my Exhibit LK-3. Additionally, as noted in footnote 8, after TECO made the filing, the Company, OPC, and other parties entered into a settlement agreement dated April 27, 2020, wherein they agreed that certain costs would be removed from base rates through a base rate reduction and included in the SPPCRC when the SPPCRC is implemented. Upon approval by the PSC, this issue will have been resolved..

[16] Response to OPC POD No. 36. Additionally, as noted in footnote 8, after TECO made the filing, the Company, OPC, and other parties entered into a settlement agreement dated April 27, 2020, wherein they agreed that certain costs would be removed from base rates through a base rate reduction and included in the SPPCRC when the SPPCRC is implemented. Upon approval by the PSC, this issue will have been resolved..

impact over the life of the SPP to a defined threshold, such as 2%, or 0.2% annually, over the ten-year life of the Company's proposed SPP. Such a threshold would result in prioritizing projects with greater benefits to customers and winnowing projects with lesser benefits to customers.

Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

(Whereupon, prefiled direct testimony of Helmuth W. Schultz was inserted.)

DIRECT TESTIMONY

OF

Helmuth W. Schultz, III

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 20200069-EI

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Helmuth W. Schultz, III. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, ("Larkin") Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan, 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, P.L.L.C.

A. Larkin performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorney generals, etc.). Larkin has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including water and sewer, gas, electric and telephone utilities.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH DESCRIBES YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. I have attached Exhibit No.__(HWS-1), which is a summary of my background, experience and qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC COMMISSION AS AN EXPERT WITNESS?

A. Yes. I have provided testimony before the Florida Public Service Commission ("Commission" or "FPSC") as an expert witness in the area of regulatory accounting and storm recovery in numerous cases as listed in Exhibit No.__(HWS-1).

Q. BY WHOM WERE YOU RETAINED, AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Larkin was retained by the Florida Office of Public Counsel ("OPC") to review the request by Duke Energy Florida, LLC ("Duke Energy", "Duke" or "Company") in its petition to this Commission for approval of its 2020-2029 Storm Protection Plan ("SPP") pursuant to Rules 25-6.030 and 28-106.201, Florida Administrative Code ("FAC"). My review is focused on accounting and cost analysis.

<u>II. BACKGROUND</u>

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE COMPANY'S REQUEST.

A. Docket No. 20200069-EI is a petition by Duke for approval of its 2020-2029 Storm Protection Plan ("SPP"). Approval of the SPP is necessary for the Company to implement a request for recovery of storm hardening costs by means of a recovery clause.

III. FILING

Q. IS THE FILING SUFFICIENT FOR APPROVAL BY THE COMMISSION?

A. I do not believe it is sufficient. There are some general concerns and a specific concern from an accounting prospective that should be addressed prior to approval by the Commission.

Q. IF YOUR CONCERNS ARE SUFFICIENTLY ADDRESSED AND CHANGES ARE MADE, WOULD THE FILING BE SUFFICIENT IN YOUR OPINION?

A. My concerns are cost driven and from an accounting prospective. I cannot address any engineering concerns and/or administrative concerns identified by others.

IV. GENERAL CONCERNS

Q. WOULD YOU IDENTIFY YOUR FIRST GENERAL CONCERN WITH THE FILING?

A. Yes. Rule 25-6.030(2)(a) defines a storm protection program as a category, type, or group of related storm protection projects that are undertaken to enhance the utility's existing infrastructure for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions, therefore improving overall service reliability. Rule 25-6.030(2)(a) defines a storm protection project as a specific activity within a storm protection program designed for the enhancement of an identified portion or area of existing electric transmission or distribution facilities for the purpose of reducing restoration costs and reducing outage times associated with extreme weather conditions, therefore improving overall service reliability. In response to Staff Interrogatory No. 1-1, the Company stated that various programs are new. This I found concerning since the Company has been performing various work to improve the infrastructure of its system and this response gave me the impression that the only benefit to come from the hardening activities would be a reduction to storm costs. This hardening, while designed to reduce future storm costs, should also have an impact on costs currently incurred by the Company and included in base rates. This impact would be in the form of base rate cost reductions for hardening work currently being performed and the work itself would presumably have an impact on the level of maintenance costs currently being incurred and that cost similarly should be a cost savings resulting from the SPP program work performed. Citizens' Interrogatory No. 4-130 asked for specific detail with respect to the cost savings. In response, Duke stated:

> The explanation of reduced outage times and costs in extreme weather conditions is provided in Exhibit No. __ (JWO-2). Intuitively, the programs will also provide cost savings during normal operating conditions, which is what is being referred to in the testimony. DEF has not performed the necessary analysis to quantify estimated cost savings during normal operating conditions (i.e., non-extreme weather conditions).

The Company acknowledges that there would be cost reductions; however, without quantification of those savings, even an estimated amount, there is a risk that ratepayers will be paying for improvements that will reduce the Company's costs in base rates but those savings will not be passed through to the ratepayers unless base rates are reduced accordingly. At a minimum the Commission should identify this as an area of concern and place Duke on notice that it will be addressed in the next general base rate case filed by the Company.

Q. DO YOU HAVE ANY OTHER GENERAL CONCERNS WITH THE FILING?

A. Yes. Duke was requested in multiple interrogatories[1] to explain in detail how the capitalized and O&M amounts on various pages of Exhibit No. (JWO-1) were determined. The responses were similar to the following response to Interrogatory No. 133:

> Capital unit cost consists of labor and materials based on historical averages and guidance from Finance for Indirect overheads. O&M is 1.25% of the Capital unit cost based on historical averages.

Clearly, this response is not a detailed explanation as it provides no specific details or determinations.

Q. WHY IS SPECIFIC COST DETAIL SO IMPORTANT FOR THIS FILING?

A. The SPP filing is the precursor to the cost recovery filing. Rule 25-6.030(3)(d) and (e) requires a cost estimate for capital and operating costs[2] along with a description of the respective projects[3]. While I did not participate in the development of Rule 25-6.030 and Rule 25-6.031, I am confident that the referencing of specific cost information (i.e. capital and operating expenses) by project was not intended to serve as a best wild guess of projected costs or a blank check for initial recovery of costs as part of the Storm Protection Plan Cost Recovery Clause ("SPPCRC"). The estimated costs to be recovered need to be developed with specific detail in a manner that would not allow

[1] Citizens' Interrogatory Nos. 133, 137,141, 148, 152, 158 and 167.
[2] Rule 25-6.030 (3)(d)(3) and (4) and Rule 25-6.030(3)(e)(1)(c).
[3] Rule 25-6.030(3)(e)(1).

for an arbitrary recovery of costs that are not based on substantive cost detail. I will discuss why I am concerned with the lack of detail on how costs were developed.

Q. DO YOU HAVE OTHER CONCERNS WITH HOW THE COMPANY REPLIED TO REQUESTS REGARDING THE COSTS PROJECTED OR ITS COMPLIANCE WITH RULE 25-6.030?

A. Yes. My understanding of Rule 25-6.030 is that it sets the blueprint for the cost recovery clause. The plan must be in effect and properly established so that the SPPCRC can function properly and as intended. Since Rule 25-6.030(3)(h) refers to the impact on rates and Rule 25-6.031(6)(b) states costs included in clause recovery shall not include costs recovered through the utility's base rates, the information that is included in the cost requirement provisions in the SPP should exclude costs recovered through the utility's base rates. Duke was requested in multiple interrogatories to provide comparable costs that would be included in base rates during 2020-2022 to the cost estimates included in Exhibit No._(JWO-1)[4]. The Company's responses did not provide the information for base rates as requested. Instead, the responses generally were similar to the response to Citizens' Interrogatory No. 132 which was as follows:

> Subject to and without waiving DEF's objection submitted contemporaneously to this request, Exhibit No. ___(JWO-1), Page 5, has a "3-Year Scope" table, which includes the estimated costs of the work to be performed for the years 2020-2022. The table also includes the number of units by year. The number of customers for 2020 are included in the "2020 Planned Duke Energy Florida – Targeted Underground (TUG)" table in Exhibit No. ___(JWO-1), Pages 6-10. Per the SPP rules, location identification was only required for Year 1. Therefore, the number of customers, which are tied to specific locations, are only available for Year 1. For 2022, as described in the footnote of

[4] Citizens' Interrogatory Nos. 132,136,140,144,147,151,155,157,161,166, 170, 174, 176, 179 and 181.

> the “3-Year Scope” table on Page 5, this work will be incorporated into the Lateral Hardening Program beginning in 2022.

This response suggests there are no costs currently in base rates for any of the planned work which is not correct. Duke has been engaged in hardening activities and is recovering these costs through its current base rates. Absent recognition of these amounts, a clause petition could result in double recovery if the costs are not identified and accounted for appropriately.

Q. THE COMPANY HAS INCLUDED IN EXHIBIT NO.__(JWO-2), PAGE 40 A TABLE THAT SHOWS WHAT THE IMPACT IS ON REVENUE REQUIREMENT AND RATE IMPACTS THAT SHOW 2020 HAS NO CLAUSE RECOVERY AND 2021 WILL HAVE MINIMAL CLAUSE RECOVERY. WOULD THAT ELIMINATE YOUR CONCERN?

A. Not entirely. I agree that this exhibit indicates Duke is seeking no recovery for 2020, recovery of $8.8 million in costs for 2021, recovery of an estimated $105.6 million in costs for 2022. The Plan as filed in the SPP is to provide the framework for the SPPCRC. If the issues with how these cost estimates were determined are not addressed in this docket, Duke as well as other utilities could assume that the methodologies employed are sufficient for estimating costs going forward in the years 2021 and 2022. Based upon my expertise and experience, changes are necessary to comply with the applicable rules and underlying statute.

<u>V. SPECIFIC CONCERNS</u>

Q. YOU INDICATED EARLIER THAT THERE WAS A SPECIFIC CONCERN WITH THE COSTS PROJECTED FOR THE RESPECTIVE PROJECTS. WOULD YOU EXPLAIN WHAT YOU FOUND?

A. Yes. Duke was requested in multiple interrogatories to provide actual costs and status for projects with a start date prior to April 15, 2020[5]. The responses to those interrogatories provided a listing of projects with an indication of whether the project was completed or in progress along with the actual cost capitalized and/or charged to O&M for completed projects. The responses provided some significant and important information for comparing the estimates to actual. On Exhibit HWS-2, I summarized the estimated and actual costs for 33 Planned Targeted Underground projects listed as being completed. The result was that the projected capital costs of $3,951,335 for those 33 projects were overestimated by $2,174,948 or 55.04%. Exhibit HWS-3 shows the results for the six 2020 Planned Deteriorated Conductor projects and costs along with the five 2020 Planned Self Optimizing Grid projects and costs completed. The projected capital costs of $1,389,561 for the six 2020 Planned Deteriorated Conductor projects appear to be overestimated by $344,919 or 24.82%. The projected capital costs of $298,476 for the five 2020 Planned Self Optimizing Grid projects appear to be overestimated by $119,794 or 40.14%.

Exhibit HWS-4 shows the results for the 2020 Planned Distribution Pole Replacement projects completed. The projected capital costs for these projects appear to be overestimated by approximately $7,711,326.

[5] Citizens' Interrogatory Nos. 134, 138, 142, 145, 149, 159, 162, 164 and 171.

Q. WHY DIDN'T YOU PROVIDE A PERCENTAGE OF THE OVERESTIMATED COSTS FOR THE 2020 PLANNED DISTRIBUTION POLE REPLACEMENT PROJECTS? WHY DID YOU ESTIMATE THE OVERSTATEMENT?

A. Duke's response for these projects was different from its other discovery responses. Duke identified specific projects as completed but the unit count for the specific project was different. For example, the projects listed as complete included a total of 2,668 units in the projection of $22,072,989 of capital costs at an average cost of $8,273. The same projects listed as complete only had 873 units completed at a cost of $4,699,300 at an average cost of $5,383 per unit. Therefore, I could not make a similar analysis to that shown in my earlier exhibits. I determined the best way to proceed was to calculate an approximate overestimate by the Company on a per unit basis. The completed cost difference of $2,890 ($8,273-5,383) multiplied by the 2,668 total projected units gives an approximate overestimate of $7,711,326.

Q. WERE ANY OF THE SPECIFIC POLE PROJECTS COMPLETED IN THEIR ENTIRETY?

A. It is not clear from Duke's responses. However, some projects appear to have been completed. For example, the Deland project estimated 234 units at an average cost of $8,316 and the completed numbers show 252 units at an average unit cost of $2,877. That unit cost difference of $5,439 is significant and indicates my current estimate of the Company's overstatement of costs is low. Similarly, the two listed Monticello projects estimated costs of $373,442 for a combined 45 units for an average unit cost of $8,299. Actual costs for 44 units are $192,304, for an average of $4,371 per unit. Here again, the apparent difference is significant.

Q. DO YOU HAVE ANY OTHER INFORMATION THAT YOU ARE AWARE OF THAT WOULD CAUSE YOU TO QUESTION THE ESTIMATES?

A. Yes. I have reviewed numerous storm cost recovery requests for many utilities, including Duke. When I observed the unit cost for pole replacements, I questioned whether these costs were consistent with the costs incurred by the Company in storms despite storm work being done under less than desirable conditions as opposed to blue sky days when the hardening work that is the subject of this docket would be performed. Duke's response to Citizens' Interrogatory No. 1-31 provided a summary of the capitalized costs for Hurricane Michael in Docket No. 20190110-EI. The Company identified $533,196 of material and burden costs plus $8,067,155 for labor and burden costs resulting in a total capital cost of $8,600,351. The number of poles identified as being capitalized was 1,970 which gives an average per pole cost of $4,366 ($8,600,351/1,970). Duke's same response provided information for Tropical Storm Alberto. The capitalized cost for 13 poles was $55,218, for an average of $4,248. The lower cost for work being performed during storm restoration raises a concern when compared to the $8,273 cost per unit for poles that Duke is showing in its SPP filing. Clearly, without more explanation than has been provided by Duke so far, there is a problem with either the rate used during storm restoration or the estimates included in the current filing in this docket.

Q. ARE YOU AWARE OF ANY OTHER UNIT COSTS WHERE DIFFERENCES EXIST THAT CAUSE YOU TO QUESTION THE ESTIMATES?

A. Yes. Similar to the pole replacement costs, the replacement of wire is significantly different. For example, Duke's response to Citizens' Interrogatory No. 138 stated the unit count for Deteriorated Conductor in circuit feet. The cost per unit for Deteriorated Conductor is $47.59 per circuit foot. However, Duke's response to Interrogatory No. 1-36, in Docket No. 20190110-EI, states the capitalized loaded material and labor cost for replacing 821,246 feet of wire was $3,824,318. That shows $4.66 per circuit foot. When compared to the $47.59 cost per foot in the SPP filing, this difference is significant. Replacing conductors during or immediately following a storm event as compared to replacing deteriorated conductors during blue sky days is not the same exact activity; however, cost of the replacement wire is close enough to warrant a detailed explanation of why there is such a material cost disparity and how the cost per unit was developed for the SPP filing.

Q. WHAT DOES EXHIBIT HWS-5 INDICATE?

A. Exhibit HWS-5 shows the projected capital costs for the 2020 Planned Transmission Pole Replacement projects of $4,113,248 appears to exceed the actual costs by $819,958 or 19.93%. I would note that the actual costs included an additional 10 units. The average estimated unit cost was $41,548 and the average actual unit cost for completed projects was $30,214. Again, this shows a significant apparent difference that supports why it is important to know the details as to how costs were developed and estimated, and that by all appearances the methodology results in an excessive estimate.

Q. THE RESULTS YOU PROVIDED COVER FIVE PLAN AREAS. DID YOU INQUIRE ABOUT OTHER COST ESTIMATES?

A. Yes. As I indicated earlier, there was an inquiry into various actual costs to date based on the start dates in the various planned estimates. For example, Citizens' Interrogatory No. 4-162 inquired about the planned Pole/Tower Inspections; Duke's response indicated no actual costs were available. Citizens' Interrogatory No. 4-164 inquired about the planned spending for Tower Replacements. Duke's response indicated one project was under construction. The Company responded in a similar fashion to Citizens' Interrogatory No. 4-171 that inquired about planned Substation Hardening.

Q. WERE YOU ABLE TO IDENTIFY HOW DUKE DETERMINED THE ESTIMATES INCLUDED IN ITS RESPECTIVE PLAN COST CATEGORIES?

A. Based upon Duke's limited responses, it appears the amounts were determined based on unit costs multiplied by the expected units to be replaced. As shown in my exhibits, the unit costs for estimates are very similar, yet they are different from what Duke is showing as the actual completed unit costs. The referenced averaging used by the Company needs to be evaluated to determine why those unit costs result in significant differences from what the company is stating are actual costs. For example and as discussed earlier, Duke's unit cost for 2020 Planned Deteriorated Conductor appears to be $47.59 per unit; however, based on the over/(under) on Exhibit HWS-3, this cost varies significantly from project to project . In reviewing and presenting the estimates and actual costs to the Commission for evaluation and cost recovery, the Company's methodology must be revised.

Q. WHAT DO YOU RECOMMEND THE COMMISSION DECIDE WITH RESPECT TO THE COST ACCOUNTING FOR THE PLAN FILED BY DUKE?

A. The Company must be required to provide a more in-depth level of detail in requesting recovery of costs. Additionally, the method used must be based on detail that can be verified for reasonableness. Further, the Commission's SPP determinations should be based on a cost recovery estimate that is more in line with what actual costs may be.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes it does.

(Whereupon, prefiled direct testimony of Kevin Mara for Docket No. 20200070-EI was inserted.)

DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20200070-EI

I. INTRODUCTION

Q. WHAT ARE 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 20 additional states.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

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

In 2001, we merged our operations with GDS Associates, Inc., and Hi-Line Engineering became a department within GDS. I serve as the Principal Engineer for Hi-Line Engineering and am Executive Vice President of GDS. 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; 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

- 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 was retained by the Florida Office of Public Counsel ("OPC") to review Gulf Power's ("Gulf" or "Company") proposed 2020-2029 Storm Protection Plan ("SPP") 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 expert opinion regarding issues raised in Gulf's proposed 2020-2029 Storm Protection Plan.

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

A. I reviewed the Company's filing, including the direct testimony and exhibits. I also reviewed the Company's responses to OPC's discovery, the Company's responses to the Florida Public Service Commission ("PSC" or "Commission") 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 covering a utility's immediate 10-year planning period.

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

A. I first discuss the purpose of storm hardening and an SPP as informed by rule 25-6.030 F.A.C., including the concept of "resiliency," and I distinguish the concepts of "resiliency" and "reliability." I then discuss the critical role quantifiable benefits play in the analysis and review of an SPP. Finally, I discuss my analysis of the new programs proposed in the SPP, including principles that should be applied when reviewing Gulf's proposed SPP. In the discussion of the principles I applied, I include criteria that, in my expert opinion, the Commission must weigh to properly evaluate the sufficiency of the SPP and each SPP program under the statutes and rules governing the SPPs.

II. THE PURPOSE OF STORM HARDENING

Q. PLEASE DISCUSS FLORIDA SENATE BILL 796 (2019), AND THE RESULTING SECTION 366.96, FLORIDA STATUTES, FROM YOUR PERSPECTIVE AS AN ELECTRIC UTILITY DISTRIBUTION ENGINEER.

A. As the Commission is aware, in 2019 the Florida Legislature passed Senate Bill 796 regarding Storm Protection Plan and Storm Protection Plan Cost Recovery and the Governor signed the bill on June 27, 2019. Section 366.96, Florida Statutes, resulted. The purpose of storm hardening is stated as follows: "Protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers."[1] Further, the statute states, "All customers benefit from the reduced costs of storm restoration."[2]

The Florida Legislature directed the Commission to consider "the estimated costs and benefits to the utility and its customers of making the improvements proposed in the [SPP]."[3]

All of the SPPs should be 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 should result in lower costs for restoration from the storms and reduced outage times experienced by the customers. In my opinion, clearly, the goal is to invest in storm hardening activities that benefit the customers of the electric utilities at a cost that is reasonable relative to those benefits.

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

[1] Section 366.96(1)(d), Fla. Stat. (2019).
[2] Section 366.96(1)(f), Fla. Stat. (2019).
[3] Section 366.96(4)(c), Fla. Stat. (2019).

A. Rule 25-6.030, F.A.C., mandates that after its initial SPP, each utility must file an updated SPP at least every three years that covers the utility's immediate ten-year planning period. This language is significant and central to a recommendation that I make later in my testimony. The definitions in rule 25-6.030, F.A.C., help define the purpose and operation of the rule and statute. Per the rule, a storm protection *program* is a group of storm protection projects that are undertaken to enhance the utility's existing infrastructure for "the purpose of reducing restoration costs and reducing outages times associated with extreme weather conditions."[4] 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."[5]

The utility is required to provide, within the SPP, a description of how implementation of the projects will reduce restoration costs and outage times associated with extreme weather. Specifically, for each proposed storm protection program, the utility is to provide "an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions."[6]

Rule 25-6.030, F.A.C., requires utilities to provide budgets for projects and to provide the estimated reduction in restoration costs. 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. Any project can claim to reduce outage time/cost, but the project must be cost effective for customers to benefit. To summarize, without giving consideration to benefits achieved for

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

the projects, there will be no limit on expenditures for the storm protection plan, which is not contemplated by the SPP rule or statute.

Q. HOW IS RULE 25-6.030, F.A.C., DIFFERENT FROM THE REQUIREMENTS OF RULE 25-6.0342, F.A.C.?

A. Pursuant to now repealed rule 25-6.0342, F.A.C., a utility was required to estimate "the costs and benefits to the utility of making the electric infrastructure improvements, including the effect on reducing storm restoration costs and customer outages."[7] Previously, benefits were <u>the effect</u> on reducing storm restoration costs, while the current rule (Rule 25-6.030) now requires an estimate of the reduction of the storm restoration time and a comparison of the estimated cost of the program and resulting benefit.[8]

Q. ARE THE COSTS ASSOCIATED WITH THE SPP BEING PROPOSED TO ADDRESS SYSTEM RELIABILITY OR SYSTEM RESILIENCY?

A. They should address both concepts to some extent. To begin, it is fundamental that electric utilities have a duty to provide safe, reliable, and affordable electric service. This duty for reliable service does not mean 100% reliability, but reliability is a core function of an electric utility. Many jurisdictions, including Florida, require utilities to report on system reliability. Reliability indices include System Average Interruption Frequency Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"), which are defined in Institute of Electrical and Electronics Engineers ("IEEE") Standard 1366 - *IEEE Guide for Electric*

[7] Rule 25-6.0342 (4)(d), F.A.C., (repealed effective June 2, 2020).
[8] Rule 25-6.030 (3)(d)(1) and (3)(d)(4), F.A.C.

Power Distribution Reliability Indices. Comparison of these indices is normally done excluding major event days, which are also referred to as Major Service Outages.

On the other hand, resiliency focuses on the ability of an electric utility system to withstand and reduce the magnitude and/or duration of disruptive events.[9]

One way to consider the difference of reliability and resiliency is to compare common characteristics: [10]

Reliability: Routine, not unexpected, normally localized, shorter duration interruptions of electric service.

Resiliency: Infrequent, often unexpected, widespread/long duration power interruptions, generally with significant corollary impacts.

Because rule 25-6.030, F.A.C., references "extreme weather conditions" throughout its provisions, the projects contained in the SPP should be primarily focused on resiliency and not reliability. However, even though the primary focus should be on resiliency, the benefits from reliability cannot and should not be ignored.

Q. WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN RESILIENCY AND RELIABILITY IN EVALUATING UTILITY-PROPOSED SPP INVESTMENTS?

A. The amount of capital investment utilities proposes to invest is increasing, as indicated by the SPP proposals filed by Gulf and the other Florida electric utilities. With these increasing investments come bigger risks for the customers ultimately paying the costs. It will, therefore, be important to develop standards to evaluate whether the SPP proposals being made by Gulf and the other Florida electric utilities are cost justified. Standards will be

[9] FERC Docket RM18-1-000 Grid Reliability and Resilience Pricing

[10] *Metrics for Resilience in Theory and in Practice*, Joseph Eto, Lawrence Berkeley National Laboratory, 05/22/18.

needed to evaluate the value and cost-effectiveness of the proposed SPP programs and how they differ from traditional reliability investments that would be included and recovered in traditional utility base rates. Using traditional *reliability* measures to fully evaluate proposed system hardening expenditures to improve resiliency may not be adequate. As noted above, resilience and reliability are distinguishable concepts, and the expenditures to address improvements in each may require their own specialized evaluation criteria. There is not yet a clear and widely accepted "value of resilience" metric, so appropriate evaluation standards need to be developed by the Commission to determine the adequacy of the proposed SPPs. Moreover, while traditional measurements of reliability have been in use for many years and are widely accepted, there are not yet standardized or widely accepted standards for measuring resiliency, measurements for reliability related to resiliency, or methods of determining the value of system hardening expenditures intended to improve resiliency. Without such criteria for evaluating costs, expenditures may be undertaken by a utility for SPP programs that may not produce or result in adequate benefits related to the costs of the proposed initiatives.

Q. ARE YOU AWARE OF CLEAR STANDARDS USED IN THE ELECTRIC INDUSTRY TO MEASURE SYSTEM RESILIENCY?

A. The electric utility industry has clearly defined standards to measure system reliability using SAID, SAIFI, and CAIDI as referenced above. However, the industry does not have mature or clearly defined standards for measuring resiliency.

Q. WHAT ARE SOME METHODS FOR MEASURING SYSTEM RESILIENCY?

A. To define metrics for resiliency, it is important to consider the purpose of resiliency. Energy distribution systems provide energy for the benefit of the community in the form of transportation, health care, economic gains, etc. The goal of improving energy system resiliency is to make communities safer and more productive. Major weather events can cause widespread electric outages resulting in damage to the community and to the individual customers.

Thus, resiliency metrics should include the impact to customers and the community.[11] The following table contains suggested resiliency metrics:

Electric Service	Cumulative customer-hours of outage from extreme weather events
Critical Electric Service	Cumulative critical customer-hours of outage from extreme weather events
Restoration	Time to recover to 50% of peak number of customers out Time to recover to 75% of peak number customers out Time to recover to 100% of peak number of customers out
Monetary	Cost of Recovery Cost of grid damages
Community Function	Critical services without power more than N hours where N is less than hours of back up fuel.

The restoration time to 50% of peak is a measurement of the speed of restoration and a key component of resiliency. Generally, the 50% value is an indication of the resiliency of the transmission and substation facilities.

Critical Electric Service represents those critical customer-hours not served by the utility. A more resilient system would help prevent or minimize the outages and, if outages did occur, to restore the system more quickly. Community Function measures the impact to a

[11] *See Resilience Metrics for the Electric Power System:* A Performance-Based Approach, Sandia National Laboratories February 2017.

community and is based on the hours of outage time any critical public infrastructure (*E.g.* – first responder facilities, hospitals, critical community loads) is without utility power over N hours. Critical public infrastructure will often have backup generators with fuel supplies for 48 to 96 hours depending on building code requirements. N represents the number of hours for which the facility has backup fuel supplies. Thus, it is important that power is restored to these customers prior to their depletion of the fuel supply for the backup generator. So, N could be defined as 48 hours. The goal would be for the Community Function to have very few hours of outage time beyond their fuel supply hours. Critical Electric Service is a function of the total hours these critical public infrastructure customers are without utility power and relying instead on their backup power systems.

I recommend the Commission consider these resiliency metrics to track the effectiveness of SPP projects in future events. Limits for these parameters can help define the scope of SPP projects and may influence the speed of the roll-out of the projects.

III. <u>BENEFITS OF SPP PROGRAMS</u>

Q. YOU STATED THAT A COMPARISON OF THE ESTIMATED COST OF THE PROGRAM AND RESULTING BENEFIT IS REQUIRED BY RULE 25-6.030, F.A.C. DID GULF POWER INCLUDE QUANTIFIED BENEFITS FOR SPECIFIC PROPOSED PROJECTS OR FOR THE ENTIRE SPP?

A. No. Gulf did not provide any quantifiable benefits for any project nor did Gulf provide projected savings for its proposed SPP as a whole.

Q. WHAT INFORMATION DID GULF POWER PROVIDE REGARDING BENEFITS?

A. Section II of Gulf's Storm Protection Plan 2020-2029, is titled "2020-2029 SPP Will Strengthen Gulf's Infrastructure to Withstand Extreme Weather Conditions and Will Reduce Restoration Costs and Outage Times;" however, it contains no specific language regarding reduction in costs or reduction in outage time.

For each initiative Gulf includes a section on "benefits," I have summarized Gulf's responses regarding benefits for those initiatives in the following table:

Initiative	Gulf Power's Perceived Benefits Summarized	Quantified Cost Savings or Reduction in Outage time
Distribution Pole Inspection Program	Investments in storm hardening could reduce the extent of outages as well as restoration times from future storm events.[12]	None Provided
Distribution Feeder Hardening	Improving the storm resiliency of distribution feeders provides immediate benefits for every customer served off a hardened feeder as soon as the hardening is completed.[13]	None Provided
Lateral Undergrounding Program	Based on the overall performance of underground vs. overhead facilities and the extensive damage to Gulf's overhead facilities caused by vegetation, this program will further expand the benefits of hardening throughout Gulf's distribution system (i.e., reduced outages and restoration time).[14]	None Provided
Transmission Hardening	Steel and Concrete out-performed wood structures. Gulf will continue its program of replacing transmission wood structures with steel or concrete to ensure the resiliency of its transmission structures.[15]	None Provided

[12] *See* Exhibit MS-1, p. 8.
[13] *Id.* p. 17.
[14] *Id.* p. 21.
[15] *Id.* p. 24.

As evident in this table, Gulf Power did not quantify any reduction in outage time or savings in terms of costs for its customers. This lack of specific benefits means that any project, no matter how high the cost, could be justified by simply claiming it reduced or will reduce outages and restoration time. To satisfy the requirements of the SPP statue and rule, Gulf must estimate and quantify the benefits so that comparison to the costs can be made by the Commission.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE BENEFITS COULD BE ESTIMATED?

A. Yes. For example, Gulf's Transmission Hardening Program is focused on the replacement of wood transmission poles with steel or concrete poles. Roughly 38% of transmission poles on Gulf Power's system are wood poles which is approximately 4,600 poles.[16] The budget to replace a wood transmission pole with a steel or concrete pole is $50,000 per pole.[17] However, the estimated cost to replace a wood transmission pole during restoration efforts after an extreme weather event is $140,000.[18] Analysis from Hurricane Michael showed that 336 wood poles failed which is an 8.4% failure rate, whereas the failure rate of steel and concrete poles was 0.3%. This simple analysis demonstrates the benefit in terms of costs for storm restoration and compares that savings to the implementation costs. This type of analysis allows the Commission and stakeholders to clearly understand the value of Gulf's Transmission Pole Hardening Program and should be required by the Commission for every program proposed by Gulf.

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[16] *Id. p.* 23.
[17] *Id.* Appendix C, p. 9.
[18] Gulf's Response to OPC's Fifth Set of Interrogatories, No. 206.

Q. REGARDING THE FEEDER HARDENING PROGRAM THAT GULF POWER HAS BEEN WORKING ON SINCE 2006, DID GULF PROVIDE ANY QUANTIFIABLE BENEFITS?

A. No, there are no quantifiable benefits reported in the SPP. Gulf initiated its feeder hardening initiative in 2006 and by 2019 had completed hardening on 269 feeders.[19] The Forensics Analysis performed following Hurricane Michael collected a sampling of system assets and storm damage to perform a statistical analysis.[20] However, the analysis, which leveraged Gulf's GIS database, did not demonstrate the effectiveness of the distribution feeder hardening program. Such a demonstration potentially could have provided more justification for Gulf's change in the design parameters of the program to now include extreme wind loading ("EWL") criteria on feeder poles which was not the case prior to 2019.[21]

Without quantifiable benefits, the Commission does not have a basis to evaluate the new EWL inclusion in Feeder Hardening (or any similarly inadequately justified program) pursuant to the standards set out in the statute.

Q. WHAT IS YOUR RECOMMENDATION REGARDING GULF POWER'S PROPOSED SPP PROGRAMS?

A. In my expert opinion, the Commission should reject each program that lacks quantifiable data demonstrating the benefits of the programs. From my review of the Company's answers to interrogatories and responses to the requested production of documents, it appears that Gulf may possess quantifiable data regarding benefits for most of its proposed

[19] *See* Exhibit MS-1, p. 18.
[20] *Id.* Appendix B Section 1.2, p. 7.
[21] Direct Testimony of Michael Spoor, p. 9, lines 20-23.

initiatives. It is Gulf's responsibility to submit this type of information to support its SPP. Since Gulf has not submitted this type information, the Commission does not have enough information to evaluate the sufficiency of the SPP on this program, pursuant to the standards provided in the statute and rule, and therefore, the Commission should not approve it.

Q. SHOULD THE COMMISSION CONSIDER POTENTIAL ECONOMIC IMPACTS OF THE COVID-19 PANDEMIC IN DECIDING WHETHER GULF'S PROPOSED $998.8 MILLION SPP SHOULD GO FORWARD AT THIS TIME?

A. Yes. The uncertainty of the economic impacts of COVID-19 on the Florida economy should be considered by the Commission in reviewing Gulf's SPP. Florida's economy has been hit hard by the pandemic and has experienced a significant increase in unemployment. Section 366.96, Florida Statutes, directs the Commission to consider the estimated annual rate impact resulting from implementation of the Plan during the first three years.[22] In the first three-year period of the SPP, Gulf budgeted $247.9 million in various programs.[23] In determining, the rate impact of this investment, the Commission needs to consider the state of the economy and the affordability of electric service where there are uncertainties associated with the economic impact from the COVID-19 pandemic. Because we are still in the middle of the pandemic and do not know the full impact to the Florida and national economy or when the pandemic may end, I recommend the Commission direct Gulf to re-file or file an update to its plan in 2022 to consider the impacts of the pandemic and the effects to Florida citizens and businesses. If Gulf was required to update the SPP in 2022

[22] Florida Statues, Section 366.96(4)(d).
[23] *See* Gulf Response to OPC Second Request for Production of Documents, No. 15.

after the conclusion of the 2021 rate case, it would not be unreasonable for the Commission to allow Gulf to implement and submit for prudence determinations the core programs of the SPP including

- Distribution mainline feeder patrol program,
- Distribution – Pole Inspections,
- Transmission – Inspections,
- Distribution – Vegetation Management, and
- Transmission – Vegetation Management.

These programs have been developed and in use for many years as part of Gulf's approved SHP and the three-year total expenditure is $44.13 million. Accordingly, I would not find it unreasonable if the Commission approves the SPP with the modification that allowed the core programs to go forward and ordered a delay in implementing the other hardening programs until Gulf can provide the rate impact of all programs updated with the economic impact of the COVID-19 pandemic.

IV. <u>NEW SPP INITIATIVES</u>

Q. HAS GULF POWER OFFERED ANY NEW INITIATIVES IN THE SPP?

A. Yes. Gulf has offered several new initiatives that were not in Gulf's 2019 Storm Hardening Plan ("SHP") approved by the Commission on July 29, 2019.[24] These new initiatives are as follows;

- Lateral Undergrounding Program
- Substation Flood Monitoring and Hardening, and
- Transmission and Substation Resiliency Program.

[24] Docket No. 20180147-EI, Order No. PSC-2019-0311-PAA-EI (July 29,2019).

Q. CAN YOU DESCRIBE THE LATERAL UNDERGROUNDING INITIATIVE?

A. Yes. Gulf is proposing a new lateral undergrounding program which is intended to protect certain overhead laterals during extreme weather events by converting the laterals to underground. Gulf's laterals are located on smaller roads, in neighborhoods, and in other areas that can create access issues.[25] Gulf also stated the program is built upon the experiences of Florida Power & Light Company ("FPL"), but Gulf's laterals are different from FPL's laterals, because FPL often builds laterals behind homes which are not accessible to trucks. Without adequate access, FPL's repair times are significantly longer compared to Gulf's repair times.

Q. GULF POWER HAS APPROXIMATELY 7,000 LATERALS WHICH REPRESENTS 5,063 MILES OF OVERHEAD LINES.[26] IN ITS SPP, DID GULF POWER INCLUDE THE METHODOLOGY IT USED TO SELECT AND PRIORITIZE PROPOSED STORM PROTECTION PROJECTS INCLUDING THE LATERAL UNDERGROUNDING?

A. No. Gulf does not meet the requirement set forth in rule 25-6.030 (3)(e)(1)(d), F.A.C.[27] Gulf's SPP provided only very vague criteria that begin with overall feeder performance and customer density. Gulf states that priority will be given to laterals impacted by recent storms and based upon the lateral's history of vegetation-related outages. However, Gulf also stated the program is built upon the experiences of FPL. I understand that FPL intends to underground all laterals on a feeder. Therefore, if Gulf follows FPL's lead, the

[25] *See* Exhibit MS-1, pp. 20-21.
[26] *Id*. p. 20.
[27] FAC 25-6.030 (3)(e)(1)(d). See "a description of the criteria used to select and prioritize proposed storm protection projects."

performance of a lateral is not truly a consideration for prioritizing undergrounding activities. The only parameter for prioritizing feeders that Gulf offers is the feeder's overall performance with no clearly stated definition of overall performance.

In my opinion, it is not cost effective to underground all laterals, especially if the lateral is along a road or other thoroughfare with easy access for line crews. Gulf must provide its justification for prioritizing laterals, subject to discovery, expert review, and testimony, before the Commission should consider whether to approve, deny, or approve the program with modifications.

Q. HAS GULF POWER MADE A COMPARISON OF THE COSTS AND BENEFITS OF LATERAL UNDERGROUNDING?

A. No. Gulf admits that the Lateral Undergrounding Program is new and the first year is designed to help it learn best methods. Costs for undergrounding have been provided for the first year but only vague notions of the performance of underground versus overhead facilities during Hurricane Michael were presented.[28] I note that FPL's data show that the average cost to restore power to a lateral was $44,880 per lateral,[29] but the cost to underground a single lateral for FPL is $755,778.[30] Gulf just experienced a devastating hurricane in 2018; thus, it is conceivable that Gulf would have data for the cost of lateral repairs and the times to restore these laterals. This data would help the Commission to determine the benefit in reducing costs to restore laterals as well as the benefit from a reduction in outage time, which is necessary to properly evaluate whether this initiative

[28] *See* Exhibit MS-1, p. 21.
[29] *See* Exhibit MJ-1, Florida Power & Light Company Storm Protection Plan 2020-2029, Appendix A. Average Construction ManHour (CMH) to restore a lateral is 43.7for Hurricane Michael and Irma. Cost per CMH is $1027 for Irma per Exhibit MS-1, P. 4
[30] *Id.* Appendix C.

should be approved by the Commission. This data, to the extent it was available prior to submission of testimony, should have been provided for analyze as part of my direct testimony.

Q. WHAT IS YOUR RECOMMENDATION REGARDING LATERAL UNDERGROUNDING?

A. In my opinion, since Gulf's prioritization scheme for lateral undergrounding is not clearly defined, this project should not be included in the SPP until such time as Gulf can provide the information discussed above. Further, benefits and costs need a critical comparison to determine if customers are receiving adequate benefits for the higher rates due to this program. Without such data, the Commission does not have enough information to evaluate the sufficiency of this program within the SPP in order to meet the statutory requirement to either approve, deny or approve it with modifications. Therefore, in my expert opinion and according to the statute and rules, it should be denied.

Q. CAN YOU DESCRIBE THE SUBSTATION FLOOD MONITORING AND HARDENING INITIATIVE?

A. Yes. After Hurricane Michael, Gulf Power initiated a program to re-evaluate substations using the Coastal Substation Risk Assessments. This assessment is designed to identify substations threatened by flooding and/or storm surges. This assessment also considered the strength of the switch house, which houses the electronic relays, controls, and SCADA communication hardware, to withstand hurricane force winds.

Based on this assessment, which is essentially used to prioritize the projects, Gulf plans to implement flood monitoring on vulnerable substations and review switch house construction standards.[31] The initial projects include flood monitoring at six substations at an approximate cost of $20,000 per substation. In addition, Gulf is planning to storm harden three switch houses at a cost of approximately $300,000 per control house.[32]

Q. HAS GULF POWER MADE A COMPARISON OF THE COSTS AND BENEFITS FOR THE SUBSTATION FLOOD MONITORING AND HARDENING INITIATIVE?

A. No. Gulf's only stated benefit from flood monitoring is the ability to proactively de-energize those substations susceptible to flooding to reduce damage to powered substation equipment.[33] There is no mention of benefits from the hardening of the switch houses. Gulf has not sustained any damage from flood waters in substations in the last five years.[34] Although, during Hurricane Michael, one switch house suffered wind damage which cost $753,501 to replace and 14 other switch houses had minor repairs.[35]

Q. WHAT IS YOUR RECOMMENDATION REGARDING SUBSTATION FLOOD MONITORING AND HARDENING INITIATIVE?

A. In my opinion, Gulf has not shown a quantifiable benefit for flood monitoring since there have been no damages. The switch house hardening for only three substations exceeds the cost of any extreme storm damage sustained over the last five years. However, because the loss of a switch house puts the substation out of service, this type of project could be justified, but only if Gulf defines the cost savings or reduction in restoration time in the

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[31] *See* Exhibit MS-1, p.23.
[32] *Id.* Appendix C p. 9.
[33] *Id.* pp. 24-25.
[34] Gulf's Response to OPC's Fourth Set of Interrogatories, No. 161.
[35] Gulf's Response to OPC's Fourth Set of Interrogatories, No. 162.

event a switch house structure fails. Gulf has failed to provide that quantifiable benefit. Without such data, the Commission does not have enough information to evaluate the sufficiency of this program within the SPP in order to meet the statutory requirement to either approve, deny or approve it with modifications. The proposed Substation Flood Monitoring and Hardening initiative should, therefore, be denied.

Q. CAN YOU SUMMARIZE YOUR UNDERSTANDING OF GULF'S TRANSMISSION AND SUBSTATION RESILIENCY PROGRAM?

A. Yes. This program is designed to invest in the overall strengthening of the electric grid at the transmission and substation level to remove critical single points of failure that have the potential to impact a large number of customers.[36] An example of a single point of failure would be a substation with a single power transformer. If the transformer fails (single point of failure), customers served through the substation would be without power. A common solution is to install a redundant transformer in the substation. Another example of a single point of failure, is a radial transmission line that serves one or two substations. If the transmission line fails, both substations will be without of power and so will the customers served by these substations. A second transmission feed creating a loop will solve this single point of failure.

Gulf provided no information for projects for year two and year three in its plan; therefore, it is not possible to describe exactly how Gulf will solve these single point of failures in future years.

[36] Direct Testimony of Michael Spoor, p. 12, lines 4-8.

Q. DID GULF POWER INCLUDE A METHODOLOGY FOR PRIORITIZING THE TRANSMISSION AND SUBSTATION RESILIENCY PROGRAM?

A. No. Gulf simply stated, "based on customer impact and prioritization, Gulf is engaged in the process of removing single points of failure."[37] When OPC inquired as to whether or not there was in fact a priority method being employed, Gulf responded that all prioritization for the single point of failure program is in the SPP.[38] Based on the customer impact and prioritization contained in the SPP there is not sufficient information for the Commission and stakeholders to understand the purpose or priority of a program slated to spend $49,720,000.[39] Without such information, the Commission does not have enough information to evaluate the sufficiency of this program within the SPP in order to meet the statutory requirement to either approve, deny, or approve it with modifications. The proposed Transmission and Substation Resiliency Program should therefore be denied.

Q. HAS GULF POWER MADE A COMPARISON OF THE COSTS AND BENEFITS FOR THE TRANSMISSION AND SUBSTATION RESILIENCY PROGRAM?

A. No. Gulf has only provided vague statements such as "removing single points of failure is to provide redundancy in single transformer substations and to provide additional feeds and/or equipment to improve storm resiliency."[40] Before adding a second transformer to a substation, an analysis of the distribution system to withstand an N-1 contingency[41] should be made. Since this is extreme weather event resiliency, this analysis should be conducted at some load values less than peak loads. If the existing distribution system has

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[37] *See* Exhibit MS-1, p. 24.
[38] Gulf's response to OPC's Fourth Set of Interrogatories, No.166.
[39] *See* Exhibit MS-1, Appendix C, p. 9.
[40] *Id. p.* 25.
[41] N-1 is defined as no single failure of a piece of equipment should cause customers to lose power. In this case, the loss of a transformer in a substation.

redundancy—and many urban substations will have redundancy—there is no need for a second transformer. There is no evidence that such an analysis was made by Gulf or if the analysis is part of any prioritization for these investments.

Another possible solution to consider is the use of a mobile substation which is designed exactly for a single point of failure. During Hurricane Michael, Gulf had one single point of failure event during the hurricane, which required the utilization of a mobile substation. Further, Gulf implies that there will be new transmission lines to provide backfeeding to some unidentified substations. The justification for redundant transmission feeds needs close scrutiny by the Commission. Transmission loops that benefit multiple substations should have a higher priority than a loop for a single substation. There is no evidence that this type of analysis was performed by Gulf to determine a priority for this high cost program. Without this analysis, the Commission does not have enough information to evaluate the sufficiency of this program within the SPP in order to meet the statutory requirement to either approve, deny or approve it with modifications. This is a further reason why the proposed Transmission and Substation Resiliency Program should be denied.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TRANSMISSION AND SUBSTATION RESILIENCY PROGRAM?

A. In my opinion, Gulf has not shown in sufficient detail that there is a benefit for a program initiated due to a single transformer failure that occurred during Hurricane Michael which was alleviated by a mobile substation. Gulf failed to provide a prioritization method for this program. As a result, the Commission does not have enough information to evaluate the sufficiency of this program within the SPP in order to meet the statutory requirement to either approve, deny, or approve it with modifications, and therefore, in my expert opinion, should not approve it.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. In its proposed SPP, Gulf has failed to provide benefits for programs as required by rule 25-6.030, F.A.C., in a format that allows a meaningful comparison of the benefits to the costs of the projects or programs. The requirements regarding storm hardening activities have changed with the advent of the SPP statute and rules. Rule 25-6.030, F.A.C., clearly requires some quantitative comparison of benefits and costs. Without some means of comparison, the utility could simply justify every project or program with amorphous, unsupported claims of reducing restoration costs and/or outage time.

Further, Gulf has proposed several new projects which are vague in scope and purpose. The Transmission and Substation Resiliency Plan has no description of projects, priority of projects, or any substantiated benefits. The only tangible information is $49,720,000 in costs, <u>with no correlated benefits to compare</u>. Thus, the Commission does not have enough information to evaluate the sufficiency of this program, and in my expert opinion, should not approve it. The Underground Lateral Program has an ill-defined priority scheme and is not shown to be have sufficient benefits (actually no benefits are defined) relative to the cost of the program. This is especially true since more of Gulf's laterals are along the roads when compared to FPL which utilizes back lot line construction in older portions of the FPL system.[42] It is not clear if every Gulf lateral on a feeder is to be undergrounded as is the case with FPL, or if Gulf will prioritize individual laterals on the system/feeders. The Commission does not have enough information to evaluate the sufficiency of this program,

[42] *See* Exhibit MS-1, Appendix C, p. 20-21

and therefore, in my expert opinion, should not approve it. Although I can see value in a first-year pilot program, the pilot program should be limited, and the information resulting from it should be thoroughly evaluated before the Commission grants approval for this program on a permanent basis. I also recommend disallowing the flood monitoring system since Gulf has not experienced substation flooding. While there have been some issues with switch house damage, Gulf has failed to demonstrate the benefits of this program.

I also recommend that Commission direct Gulf to file an updated SPP with a rate impact analysis that considers the impact of the COVID-19 pandemic. In the alternative, If such an update is ordered, it would not be unreasonable for the Commission to allow Gulf to proceed with submitting for cost recovery core programs such as inspections and vegetation management, and delay consideration of other hardening programs until Gulf has prepared an analysis on the rate impacts of these programs with the economic impact of COVID-19 pandemic.

I also recommend metrics which can be used to determine the effectiveness of the SPP on a going forward basis. These resiliency metrics should include Electric Service, Critical Electric Service, Restoration, Monetary, and Community Focus. These metrics will provide stakeholders vital information regarding the resiliency of the system.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Kevin Mara for Docket No. 20200071-EI was inserted.)

ERRATA SHEET

WITNESS: Kevin Mara

The following table contains the corrected errata in his direct testimony.

Page	**Line**	**Original**	**Revision**
Page 13	Line 14	$10.3 billion	$10.8 billion

DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20200071-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 20 additional states.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. I received a degree of Bachelor of Science in Electrical Engineering from Georgia Institute of Technology in 1982. Between 1983 and 1988, I worked at Savannah Electric and Power as a distribution engineer designing new services to residential, commercial, and industrial customers. From 1989-1998, I was employed by Southern Engineering Company as a planning engineer providing planning, design, and consulting services for electric cooperatives and publicly-owned electric utilities. In 1998, I, along with a partner, formed a new firm, Hi-Line Associates, which specialized in the design and planning of electric distribution systems. In 2000, Hi-Line Associates became a wholly owned subsidiary of GDS Associates, Inc. ("GDS") 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; 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
- 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 was retained by the Florida Office of Public Counsel ("OPC") to review Florida Power & Light's ("FPL" or "Company") proposed 2020-2029 Storm Protection Plan ("SPP" or "Plan") on behalf of the OPC. Accordingly, I am appearing on behalf of the Citizens of the State of Florida.

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

A. I am presenting OPC's recommendations regarding FPL's proposed 2020-2029 Storm Protection Plan.

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

A. I reviewed the Company's filing, including the direct testimony and exhibits. I also reviewed the Company's responses to OPC's discovery, the Company's responses to the Florida Public Service Commission ("PSC" or "Commission") 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.

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

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

II. THE PURPOSE OF STORM HARDENING

Q. PLEASE DISCUSS FLORIDA SENATE BILL 796 (2019) AND THE RESULTING SECTION 366.96, FLORIDA STATUTES, FROM YOUR PERSPECTIVE AS AN ELECTRIC UTILITY DISTRIBUTION ENGINEER.

A. As the Commission knows, the Florida Legislature passed Senate Bill 796 regarding Storm Protection Plan and Storm Protection Plan Cost Recovery, and the Governor signed the bill on June 27, 2019. Section 366.96, Florida Statutes, resulted. The purpose of storm hardening is stated as follows: "Protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers". Further, the statute states that "All customers benefit from the reduced costs of storm restoration."[1]

The Florida Legislature directed the Commission to consider "the estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan."[2] All of the SPPs should be 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 should result in lower costs for restoration from the storms and reduced outage times experienced by the customers. In my opinion, clearly, the goal is to invest in storm hardening activities that benefit the customers of the electric utilities at a cost that is reasonable relative to those benefits.

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

A. Rule 25-6.030, F.A.C., mandates that after its initial SPP, each utility must file an updated SPP at least every three years that covers the utility's immediate ten-year planning period.

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

This language is significant and central to a recommendation that I make later in my testimony. Per the rule, a storm protection program, is a group of storm protection projects that are undertaken 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]

The utility is required to provide, within the SPP, a description of how implementation of the projects will reduce restoration costs and outage times associated with extreme weather. Specifically, for each proposed storm protection program, the utility is to provide "an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions."[5]

Rule 25-6.030, F.A.C., requires utilities to provide budgets for projects and to provide the estimated reduction in restoration costs. These amounts must be balanced for 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. Any project can claim to reduce outage time/cost; however, the project must be cost effective for customers to benefit. To summarize, without giving consideration to benefits achieved from the projects, there will be no limit on expenditures for the storm protection plan, which is not contemplated by the SPP rule or the statute.

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

Q. HOW IS RULE 25-6.030, F.A.C. DIFFERENT FROM THE REQUIREMENTS OF RULE 25-6.0342, F.A.C.?

A. Pursuant to the now repealed Rule 25-6.0342, F.A.C., the requirement was to provide an "estimate of the costs and benefits to the utility of making the electric infrastructure improvements, including the effect on reducing storm restoration costs and customer outages."[6] Previously, benefits were the effect on reducing storm restoration costs, while the current Rule 25-6.030, F.A.C., requires an estimate of the reduction of the storm restoration time and a comparison of the estimated cost of the program and resulting benefit.[7]

Q. ARE THE COSTS ASSOCIATED WITH THE SPP BEING PROPOSED TO ADDRESS SYSTEM RELIABILITY OR SYSTEM RESILIENCY?

A. They should address both concepts to some extent. To begin, it is fundamental that electric utilities have a duty to provide safe, reliable, and affordable electric service. This duty for reliable service does not mean 100% reliable, but it is a core function of an electric utility. Many jurisdictions including Florida require utilities to report on system reliability. Reliability indices include System Average Interruption Frequency Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"), which are defined in Institute of Electrical and Electronics Engineers ("IEEE") Standard 1366 - *IEEE Guide for Electric Power Distribution Reliability Indices*. Comparison of these indices is normally done by excluding major event days which are also referred to as Major Service Outages.

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[6] Rule 25-6.0342 (4)(d), F.A.C.
[7] Rule 25-6.030 (3)(d)(1) and (3)(d)(4), F.A.C.

On the other hand, resiliency focuses on the ability of an electric utility system to withstand and reduce the magnitude and/or duration of disruptive events.[8] One way to consider the difference of reliability and resiliency is to compare common characteristics:[9]

Reliability: Routine, not unexpected, normally localized, shorter duration interruptions of electric service.

Resiliency: Infrequent, often unexpected, widespread/long duration power interruptions, generally with significant corollary impacts.

Because Rule 25-6.030, F.A.C., references "extreme weather conditions" throughout its provisions, the projects contained in the SPP should be primarily focused on resiliency, and not reliability. However, even though the primary focus should be on resiliency, the benefits from reliability cannot and should not be ignored.

Q. WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN RESILIENCY AND RELIABILITY IN EVALUATING UTILITY-PROPOSED SPP INVESTMENTS?

A. The amount of capital investment in the utilities' proposals to regulators is increasing as indicated by the SPP proposals filed by FPL and the other Florida electric utilities. It will, therefore, be important to develop standards to evaluate whether the SPP proposals being made by FPL and the other Florida electric utilities are cost justified. Standards will be needed to evaluate the value and cost-effectiveness of the proposed SPP programs and how they differ from traditional reliability investments that would be included and recovered in traditional utility base rates. Using traditional *reliability* measures to fully evaluate proposed system hardening expenditures to improve resiliency may not be adequate. As

[8] FERC Docket RM18-1-000 Grid Reliability and Resilience Pricing

[9] *See*, http://necpuc.org/wp-content/uploads/2018/05/metrics-for-resilience-eto.pdf. *Metrics for Resilience in Theory and in Practice*, Joseph Eto, Lawrence Berkeley National Laboratory, 05/22/18.

noted above, resilience and reliability are distinguishable concepts and the expenditures to address improvements in each would appear to require their own specialized evaluation criteria. There is not yet a clear and widely accepted "value of resilience" metric, thus appropriate evaluation standards will need to be developed by the Commission to determine the adequacy of the proposed SPP's. Moreover, while traditional measurements of reliability have been in use for many years and are widely accepted, there are not yet standardized or widely-accepted standards for measuring resiliency, measurements for reliability related to resiliency, or methods of determining the value of system hardening expenditures intended to improve resiliency. Without such criteria, expenditures may be undertaken by a utility for SPP programs that may not produce or result in adequate benefits related to the costs of the proposed initiatives.

Q. ARE YOU AWARE OF CLEAR STANDARDS USED IN THE ELECTRIC INDUSTRY TO MEASURE SYSTEM RESILIENCY?

A. The electric utility industry has clearly defined standards to measure system reliability using SAIDI, SAIFI, CAIDI as defined in IEEE Standard 1366. However, the industry does not have mature or clearly defined standards for measuring resiliency.

Q. WHAT ARE SOME METHODS FOR MEASURING SYSTEM RESILIENCY?

A. To define metrics for resiliency, it is important to consider the purpose of resiliency. Energy distribution systems provide energy for the benefit of the community in the form of transportation, health care, economic gains, etc. The goal of improving energy system resiliency is to make communities safer and more productive. Major weather events can result in widespread electric outages and cause damage to the community and to individual customers.

Thus, resiliency metrics should include the impact to customers and community.[10] The following table contains suggested resiliency metrics.

Electric Service	Cumulative customer-hours of outage from extreme weather events
Critical Electric Service	Cumulative critical customer-hours of outage from extreme weather events
Restoration	Time to recover to 50% of peak number of customers out Time to recover to 75% of peak number customers out Time to recover to 100% of peak number of customers out
Monetary	Cost to Recovery Cost of grid damages
Community Function	Critical services without power more than N hours where N is less than hours of back up fuel.

The restoration time to 50% of peak is a measurement of speed of restoration and a key component of resiliency. Generally, the 50% value is an indication of the resiliency of the transmission and substation facilities.

Critical Electric Service represents those critical customer-hours not served by the utility. A more resilient system would help prevent or minimize outages and, if outages did occur, to restore the system more quickly. Community Function measures the impact to a community and is based on hours of outage time for the critical public infrastructure (first responder facilities, hospitals, critical community loads, etc.) is without utility power over N hours. Critical public infrastructure will often have backup generators with fuel supplies for 48 to 96 hours depending on building code requirements. N represents the number of hours for which the facility has backup fuel supplies. Thus, it is important that

[10] *See*, https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2017/171493.pdf. *Resilience Metrics for the Electric Power System:* A Performance-Based Approach, Sandia National Laboratories, February 2017.

power is restored to these customers prior to their depletion of the fuel supply for the backup generator. So, N could be defined as 48 hours. The goal would be for the Community Function to have very few hours of outage time beyond their fuel supply hours. Critical Electric Service is a function of the total hours these critical public infrastructure customers are without utility power and relying instead on their backup power systems. I recommend the Commission consider these resiliency metrics to track the effectiveness of SPP projects in future events. Limits for these parameters can help define the scope of SPP projects and may influence the speed of the roll-out of the projects.

III. <u>BENEFITS OF SPP PROGRAMS</u>

Q. YOU STATED THAT A COMPARISON OF THE ESTIMATED COST OF THE PROGRAM AND RESULTING BENEFIT IS REQUIRED BY RULE 25-6.030, F.A.C. DID FPL INCLUDE QUANTIFIED BENEFITS FOR PROPOSED PROJECTS OR THE ENTIRE PLAN?

A. Yes. Data from FPL's Third Supplemental Amended Response to Staff's First Data Request in Docket No. 20170215-EI was used by FPL to provide benefits for existing projects that were contained in FLP's 2019 SHP in terms of costs and reduction in outage time.[11] However, FPL did not provide such data for new programs and there was no overarching analysis of the total SPP cost and benefit to customers.

Q. CAN YOU DISCUSS THE MODEL USED BY FPL TO DEMONSTRATE THE REDUCED RESTORATION TIME AND REDUCED RESTORATION COSTS WHEN FPL'S SYSTEM IS IMPACTED BY SEVERE WEATHER EVENTS?

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

A. Yes. FPL presented an estimate of the reduction in restoration time and reduction in restoration costs from severe weather events such as hurricanes.[12] These estimates were derived from FPL's storm assessment model which helps predict the damage of an incoming hurricane or tropical storm. This model can be used to estimate restoration assuming the storm hardening activity was not in place. The model uses a GIS model of the assets (poles and wires) and applies wind speeds. The model is calibrated based on actual storm data.[13] With the modeled damage, estimates can be made on the restoration construction time and total duration.

FPL modeled the system without Storm Hardening Plan ("SHP") improvements and estimated the construction man-hours (CMH) needed to restore the system based on Hurricane Michael and Hurricane Irma making landfall. This was done by using the weather data from these hurricanes and applying that to the strength of the system without SHP improvements. FPL then prepared a net present worth of the savings assuming a return cycle of hurricanes of three-years and five-years.[14] The results of FPL's analysis for Hurricane Irma is shown below:

40 Yr NPV Savings (2017$)

40 Yr NPV Savings Every 3 Years (Millions) (2017$)	40 Yr NPV Savings Every 5 Years (Millions) (2017$)
$653	$406
$3,082	$1,915

[12] *See* Exhibit MJ-1, p. 4
[13] *See* FPL's Response to OPC's Fourth Request for Production of Documents, Production of Document No. 65.
[14] *See* Exhibit MJ-1, Appendix A.

Q. IN YOUR OPINION, SHOULD FPL PROVIDE A SIMILAR ANALYSIS FOR THE SPP?

A. Yes, Rule 25-6.030, F.A.C., requires utilities to provide budgets for projects and to provide the estimated reduction in restoration costs. This will allow a comparison of benefits to costs to determine if there are savings to the utilities' customers.

In this case, FPL should model the future system with the proposed SPP program in place subjected to Hurricane Matthew and/or Hurricane Irma. These results can then be compared to the actual restoration costs of Hurricane Matthew and/or Hurricane Irma. This will represent the savings as a result of FPL's proposed SPP.

In addition, FPL should provide a net present value of the revenue requirements for the programs contained in its SPP and detailed in the Errata to Exhibit MJ-1 in Section VI. This value would then be compared to the storm restoration savings. My approximation of the 40-year net present value ("NPV") of the hardening costs would be in the range of $10.3 billion.

Q. SHOULD THE COMMISSION CONSIDER POTENTIAL ECONOMIC IMPACTS OF THE COVID-19 PANDEMIC IN DECIDING WHETHER FPL'S PROPOSED $10.2 BILLION SPP SHOULD GO FORWARD AT THIS TIME?

A. Yes. The uncertainty of the economic impacts of COVID-19 on the Florida economy should be considered by the Commission in reviewing FPL's SPP. Florida's economy has been hit hard by the pandemic and has experienced a significant increase in unemployment. Section 366.96, Florida. Statute, directs the Commission to consider the estimated annual rate impacts resulting from implementation of the Plan during the first three years.[15] In the first three-year period of its SPP, FPL budgeted $3.25 billion in various programs.[16] In determining the rate impact of this investment, the Commission needs to consider the state of the economy and the affordability of electric service where there are uncertainties associated with the economic impact from the COVID-19 pandemic. Because we are still in the middle of the pandemic and do not know the full impact to the Florida and national economy or when the pandemic may end, I recommend the Commission direct FPL to re-file or file an update to its plan in 2022 to consider the impacts of the pandemic and the effects to Florida citizens and businesses. If FPL was required to update the SPP in 2022 after the conclusion of the 2021 rate case, it would not be unreasonable for the Commission to allow FPL to implement and submit for prudence determinations the core programs of the SPP including:

- Distribution – Pole Inspections;
- Transmission – Inspections;
- Distribution – Vegetation Management; and
- Transmission – Vegetation Management.

These programs have been developed and in use for many years as part of FPL's approved SHP. The three-year total expenditure for these programs is $476.6 million.[17] Accordingly, I would not find it unreasonable if the Commission approves the SPP with the modification that allowed the core programs to go forward and ordered a delay in implementing the other hardening programs until FPL can provide the rate impact of all programs updated with the economic impact of COVID-19 pandemic. A key to this analysis will be an update to the total program cost benefit analyses using the storm damage

[15] Section 366.96(4)(d), Florida Statutes.
[16] *See* Exhibit MJ-1, Appendix C.
[17] *See* Exhibit MJ-1, Appendix C.

model to determine benefits on a forward looking basis coupled with the net present value of the costs of the SPP programs.

IV. NEW SPP INITIATIVES

Q. HAS FPL OFFERED ANY NEW INITIATIVES IN THE SPP FROM ITS 2019 SHP?

A. Yes. FPL has offered several new initiatives that were not in FPL's 2019 SHP approved by the Commission on July 29, 2019.[18] These new or modified programs are as follows:

- Substation Storm Surge/Flood Mitigation Program; and
- Expansion/Changes to the Storm Security Underground Plan (SSUP) Pilot.

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

A. Yes. This new program is designed to mitigate damage at several targeted distribution and transmission substations that are susceptible to storm surge and flooding during extreme weather events.[19] FPL discussed two substations (St. Augustine Substation and South Daytona Substation) that had flooding during Hurricane Irma. Flooding of a substation is a low-probability high-risk scenario. The flooding of a substation can be a high-risk scenario since little can be done other than to de-energize the station until flood waters have receded.

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

[18] Order No. PSC-2019-0301-PAA-EI, issued July 29, 2019, in Docket No. 20180144-EI.
[19] *See* Exhibit MJ-1, p. 30.

A. The acquisition of land for a substation is always a challenge; however, the land needs to be suitable for safe and reliable electric service. Flood maps were not issued until 1973;[20] therefore, substations constructed before 1973 would not have had standards requiring certain elevations. For example, the St. Augustine Substation was originally built in 1927 and rebuilt in 1969.[21] However, substations built after 1973 should have been designed with the knowledge of potential flood waters and the designs should have accounted for this predicable occurrence. Specifically, the ASCE-24-14 Flood Resistant Design and Construction recommends the facilities to be designed for the Basic Flood Elevation (100 year flood level) plus two feet. Details of improvements are not required to be contained in the current SPP, thus, no conclusion can be reached regarding the prudency of the original design and the proposed mitigation plans.

Q. CAN YOU DESCRIBE THE MITIGATION TO BE USED BY FPL FOR FLOOD MITIGATION?

A. Yes. FPL is suggesting that one substation will need to be re-built at a higher elevation and seven to nine other substations can be retro-fitted with flood protection walls.[22] The flood protective walls appears to be a cost effective mitigation action (pending determination of the original substation design). FPL suggests changing the elevation of the St. Augustine Substation. This would be accomplished by increasing the height of the seawall by five feet and adding fill so as to raise the elevation of the land. Once complete, the substation will be re-built on essentially the same site.[23]

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[20] *See* https://www.fema.gov/media-library-data/20130726-1602-20490-6472/nfip eval chronology.txt
[21] *See* FPL's Response to OPC's Fourth Set of Interrogatories, Interrogatory No. 214.
[22] *See* Exhibit MJ-1, p. 30.
[23] *See* FPL's Response to OPC's Fourth Set of Interrogatories, Interrogatory No. 217

The cost of the project is budgeted at $10,000,000[24] which includes $3,000,000 for the site work.[25]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS PROJECT TO RAISE THE ELEVATION OF THE ST. AUGUSTINE SUBSTATION?

A. FPL should provide an alternative project which would relocate the substation away from the water's edge to determine whether the Company's proposal is the least cost option, as required by Rule 25-6.030(3)(i), F.A.C. The cost of a new site could be offset by the cost of the site work. However, this is not necessarily the forum to discuss the pros and cons of individual projects.

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

A. I recommend inclusion of this program but limit it to the retro-fitting of the flood protection walls for the seven to nine substations. FPL provided the costs and benefits associated with the program including time of outage due to flooding which repeated in Hurricanes Irma and Michael.

Q. CAN YOU DESCRIBE THE STORM SECURITY UNDERGROUND PLAN (SSUP) PILOT?

A. Yes. In FPL's 2019 SHP, the SSUP was identified as a program targeting certain overhead laterals that were impacted by recent storms and have a history of vegetation-related

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[24] *See* Exhibit MJ-1, p. 31.
[25] *See* FPL's Response to OPC's Third Set of Production of Documents, Production of Document No. 36

outages and other reliability issues for conversion from overhead to underground.[26] This pilot program is slated for three years ending 2020, and FPL plans to convert approximately 220-230 laterals from overhead to underground.[27] FPL stated its key objectives of the SSUP pilot included validating conversion costs, testing different design philosophies, gaining a better understanding of customer impacts and identifying barriers.[28]

Q. IS FPL PROPOSING TO EXPAND THE SSUP PROGRAM IN ITS SPP?

A. Yes. FPL suggests it is expanding the application of the SSUP for the implementation of its system-wide Lateral Hardening (Undergrounding) – Distribution Program for the period of 2021-2019.[29] Total projected expenditures for the period of 2021 to 2029 is $4,981,100,000 which averages $553,500,000 per year. In my view, this is not an expansion but a new program. As stated earlier, the SSUP Pilot approved by the Commission[30] focused on key objectives such as validating conversion costs, testing different design philosophies, gaining a better understanding of customer impacts and identifying barriers. With those learning objectives met, FPL is now proposing a new distribution hardening program which includes undergrounding laterals.

Q. HAS THE PRIORITY OF THE PROGRAM CHANGED IN THE SPP?

A. Yes, the priority for selection of laterals has changed from FPL's filing in its 2019 SHP. The original priority and scope of the Pilot was to target overhead laterals experiencing an outage during Hurricanes Matthew and/or Irma and having a history of vegetation-caused

[26] Direct Testimony of Michael Jarro, p. 11, lines15-17.
[27] Direct Testimony of Michael Jarro, p. 11, lines 4-6.
[28] *See* Exhibit MJ-1, p. 22.
[29] Direct Testimony of Michael Jarro, p. 11, lines 18-21.
[30] Order No. PSC-2019-0301-PAA-EI, issued July 29, 2019, in Docket No. 20180144-EI.

outages and overall reliability.[31] The focus of the program, as conveyed to the Commission and stakeholders, was that FPL would find laterals that had a history of poor resiliency and poor reliability and convert those overhead laterals to underground. Many of these laterals, especially in older neighborhoods, are located on the customer's back property line[32] making access extremely difficult for storm restoration which increases the cost of the normal maintenance of the system.

The priority as described in the SPP is very different. FPL will prioritize based on an overall feeder performance methodology.[33] The methodology for prioritizing undergrounding budgets is based on the reliability/resiliency of <u>all</u> overhead laterals on feeders. In other words, FPL will take in account and sum up on a feeder basis the outage experience of all 20-30 laterals on a feeder during hurricanes, the number of vegetation-related outages over the last 10 years and the total number of lateral and transformer outages for the last 10 years.[34] Based on the scoring of the feeders, FPL will then underground all of the laterals on a feeder. Clearly, this methodology is much different than focusing on individual laterals with poor performance.[35]

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

A. No. Undergrounding power lines/laterals is an expensive proposition and one that should not be taken lightly. The average lateral on FPL's system is 0.13 miles long[36] and the average cost to underground a lateral is $755,778.[37]

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[31] FPL Storm Hardening Plan, page 10, in Docket No. 20180144-EI.
[32] *See* Exhibit MJ-1, p. 23.
[33] *See* Exhibit MJ-1, p. 26.
[34] *Id.*
[35] *See* Exhibit MJ-1, p. 22.
[36] *See* Exhibit MJ-1, p. 23.(23,000 miles of laterals and 180, 000 laterals)
[37] *See* Exhibit MJ-1, Appendix C (10 year average)

If FPL undergrounds all of the laterals on a feeder, then the investment per feeder will be $15,115,556 to $22,673,333 per feeder. This is a significant investment in a small portion of the system in a single community. A better course of action is not to underground all of the laterals on a feeder, but to focus on the laterals that have a history of poor resiliency and poor reliability. This way the investment can be spread to more communities in the system, which is important since all customers will be contributing to the costs of undergrounding.

In addition, the makeup of a feeder is generally not homogeneous. Some laterals will have fewer outages due to vegetation (or lack thereof), some will be located along a roadway with easy access with greater reliability, some will have few customers, and some will have no access and very poor reliability. However, under FPL's proposed program to lump all laterals together and score the priority on a feeder basis, there will be laterals that will be undergrounded that do not need to be. Thus, this would not be as effective in reducing outage times and recovery costs from extreme weather events. Given that this is a change in the methodology from the original SSUP Pilot program, there is no information available to determine how over-inclusive this new methodology would be and result in unnecessary undergrounding.

The SSUP Pilot included 497 laterals[38] and all of these laterals suffered outages in either Hurricane Irma or Michael. I note that the number of laterals without power in Irma was 23,341 and these 497 laterals are a small subset of that total. The following is a break down on the number of sustained outages for each lateral between 2015 and 2019.[39]

- 19 laterals have more than 10 outages
- 56 laterals have 6-10 outages

[38] *See* Exhibit MJ-1, Appendix E
[39] *See* FPL's Response to OPC's Fourth Set of Interrogatories, Interrogatory No. 210.

- 98 laterals have 3-5 outages
- 129 laterals have 1-2 outages
- 195 laterals have 0 outages.

This data shows that during the Pilot phase, 195 laterals to be undergrounded suffered no outages since 2015. In fact, 65% of the laterals FPL proposes to be undergrounded had two or fewer outages over the last five years. Further, 85% of these laterals had two or fewer outages related to vegetation issues. In my opinion, this program on a going forward basis should not be focused on undergrounding laterals with no significant history of outages. The population of laterals that experience an outage in Hurricane Irma was 20,341;[40] therefore, it is necessary to locate laterals where the investment will have the largest return in terms of resiliency and, to a lesser extent, improvement in reliability.

Q. WHAT IS YOUR RECOMMENDATION FOR PRIORITIZING THE LATERALS FOR UNDERGROUNDING?

A. I agree with FPL's starting point of analyzing the laterals on a feeder basis. The selection of feeders should be weighted by Management Area so as to spread the investment to all parts of the system. However, once a feeder is selected, the screening of the 20-30 laterals on the feeder should start with accessibility (or lack thereof), then the number of outages experienced, and then investment per outage hours for the last five years. The outage hours would be better than investment per number of customers, because the outage hours recognizes the difficulty of access on some lateral taps. Finally, there should be a cutoff on investment per feeder such that no more than 10 or 15 laterals are addressed per feeder.

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40 *See* Exhibit MJ-1, Appendix A p. 8 of 18.

This limit of laterals per feeder meets a goal of improving the resiliency and reliability on as many feeders as practical and, thus, improving as many communities as possible.

Q. DO YOU HAVE THOUGHTS ON THE TIMING OF THE DISTRIBUTION LATERAL HARDENING PROGRAM?

A. Yes. The accelerated rate for undergrounding has no basis or rationale. Of course, more undergrounding means better resiliency, yet this has to be balanced with the rate impacts to the customers. FPL is proposing nearly tripling its 2020 budget of $120,000,000 to $342,800,000 in 2021. By 2025, FPL proposes doubling the budget again to $631,400,000.[41]

The Distribution Feeder Hardening Program which has annual budgets of $650,000,000 will be ramping down in 2023 and closing down in 2026.[42] I recommend that the Distribution Lateral Hardening Program be ramped up slowly to match the expenditures on the Distribution Feeder Hardening Program. This essentially delays the full roll out by three years. This is shown in my Exhibit KJM-2. This reduces the total 10 year budget from $10.245 billion to $9.052 billion and levels the annual budget in the early years (2021-2023) to $1.048 billion per year.

Q. WHAT INFORMATION DID FPL PROVIDE REGARDING BENEFITS OF ITS LATERAL HARDENING PROGRAM?

A. FPL pointed out that many of the laterals are behind customers' premises making it more difficult to access and, therefore, increasing the time to restore power to these facilities compared to facilities located along the roadways.[43] FPL also noted that performance of

[41] *See* Exhibit MJ-1, Appendix C
[42] *See* Exhibit MJ-1, Appendix C
[43] *See* Exhibit MJ-1, p. 23.

underground laterals is better than overhead laterals. However, FPL provided no quantifiable benefits in terms of restoration time or restoration costs benefits to customers from extreme weather events.

Q. DID YOU CONDUCT ANY COMPARISON OF THE BENEFIT AND COST OF UNDERGROUNDING DISTRIBUTION LATERALS?

A. Yes, I did. FPL's data show that, for restoration during a hurricane event, the average cost to restore power to a lateral was $44,880 per lateral;[44] however, the cost to underground a single lateral for FPL is $755,778.[45] I know that undergrounding laterals provides much greater resiliency during extreme weather events, yet the benefit to cost ratio is so low as to be not justifiable. I also recognize that some laterals will have much longer restoration time and much higher costs for restoring power especially those in inaccessible locations. However, it is incumbent on FPL to provide data to justify these expenditures which it has not done.

Q. DESPITE THE COMMISSION'S APPROVAL OF FPL'S 2019 SHP, INCLUDING THE PILOT FOR UNDERGROUNDING LATERALS, WHAT IS YOUR RECOMMENDATION REGARDING THE UNDERGROUNDING DISTRIBUTION LATERALS PROGRAM CONTAINED IN FPL'S PROPOSED SPP?

A. To be clear, FPL's 2019 SSHP proposed a pilot program that had key objectives including validating conversion costs, testing different design philosophies, better understanding

[44] *See* Exhibit MJ-1, Florida Power & Light Company Storm Protection Plan 2020-2029, Appendix A. Average Construction Man-Hour (CMH) to restore a lateral is 43.7for Hurricane Michael and Irma. Cost per CMH is $1027 for Irma per Exhibit MS-1, P. 4
[45] *Id.* Appendix C.

customer impacts and identifying barriers. Commission approval for a pilot does not extend to approving a new program that invests $4,981,100,000 over an eight year period. This level of investment requires much greater scrutiny and consideration.

In my opinion, benefits and costs for undergrounding distribution laterals needs a critical comparison to determine if customers are receiving adequate benefits for the higher rates due to this program. Without such data, the Commission does not have enough information to evaluate the sufficiency of the SPP on this program and should not approve it. This deficiency can be remedied in a 2022 SPP update.

V. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I recommend metrics be established by the Commission which can be useful to determine the effectiveness of FPL's SPP on a going-forward basis. These resiliency metrics should include Electric Service, Critical Electric Service, Restoration, Monetary, and Community Focus.

FPL should be directed to model its future system with the proposed SPP program in place and subjected to the weather conditions of Hurricane Matthew and/or Hurricane Irma. These results can be compared to the actual restoration costs of Hurricane Matthew and/or Hurricane Irma. This will represent the savings as a result of the SPP. The net present value of the savings should be compared to the net present value of the proposed $10.2 billion in SPP programs. This information is critical for the Commission to compare the total costs of the program to the project benefits of the program.

I also recommend the Commission direct FPL to file an updated SPP in 2022 with a rate impact analysis that considers the impact of the COVID-19 pandemic and includes the required analyses that I address in my testimony. If such an update is ordered, it would not be unreasonable for the Commission to allow FPL to proceed with submitting for cost recovery core programs such as inspections and vegetation management, and delay consideration of other hardening programs until FPL has prepared an analysis on the rate impacts of these programs with the economic impact of COVID-19 pandemic.

Further, FPL has proposed two new projects entitled Substation Storm Surge/Flood Mitigation Program and Expansion/Changes to the Storm Security Underground Plan (SSUP) Pilot. I recommend that, in accordance with Rule 25-6.030(3)(i), F.A.C., FPL be directed to provide in the 2022 SPP update, an alternative to the re-building of the St. Augustine Substation which would relocate the substation away from the water's edge. The Commission does not have enough information in this docket to evaluate the sufficiency of the SSUP and FPL has not demonstrated that this program has sufficient benefits (actually no benefits are defined) relative to the cost of the program.

My testimony recommends delaying the pace of the SSUP such that the new expenditures of the SSUP to match reductions in the Feeder Hardening Program.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Ralph Smith for Docket No. 20200070-EI was inserted.)

DIRECT TESTIMONY

OF

RALPH SMITH

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20200070-EI

I. INTRODUCTION

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

A. My name is Ralph Smith. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan, 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, ("Larkin") is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?

A. Yes, I have testified before the Florida Public Service Commission ("FPSC" or "Commission") previously. I have also testified before several other state regulatory commissions.

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel ("OPC") to review Gulf Power Company's ("Gulf" or "Company") proposed 2020-2029 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 expert opinion regarding issues raised in Gulf's proposed 2020-2029 Storm Protection Plan.

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

A. I reviewed the Company's filing, including the direct testimony and exhibits. I also reviewed the Company's responses to OPC's discovery, the Company's responses to PSC Staff's discovery, and other materials pertaining to the SPP and its impacts on the Company. In addition, I reviewed Rule 25-6.030, Florida Administrative Code ("F.A.C."), concerning approval of a Transmission and Distribution Storm Protection Plan that covers a utility's immediate 10-year planning period.

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

A. I first discuss Rule 25-6.030, F.A.C., and the concept of "resiliency" and distinguish the concepts of "resiliency" and "reliability". I then discuss principles I applied when reviewing Gulf'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 each SPP under the statutes and rules governing the SPPs.

II. THE CONCEPTS OF "RESILIENCY" AND "RELIABILITY"

Q. PLEASE DISCUSS RULE 25-6.030.

A. Rule 25-6.030, F.A.C., provides that each utility must file an updated SPP at least every three years that covers the utility's immediate ten-year planning period. Rule 25-6.030, F.A.C., also specifies the information to be included in each utility's SPP. The Florida Legislature directed the Commission to adopt rules to specify the elements that must be included in each utility's SPP. The Florida Legislature found that it was in the State's interest to "strengthen electric utility infrastructure to withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management," and for each electric utility to "mitigate restoration costs and outage times to utility customers when developing transmission and distribution storm protection plans." Section 366.96(1)(c) and (e), F.S. These objectives of mitigating restoration costs and outage times by strengthening electric utility infrastructure to withstand extreme weather events appear to relate to resiliency, which, as explained below, should be distinguished from reliability, for developing specific criteria to be applied in evaluating utility proposed SPP expenditures.

Q. PLEASE DISCUSS THE CONCEPT OF "RESILIENCY".

A. The term "resilience" means the ability to prepare for and adapt to changing conditions, and withstand and recover rapidly from disruptions.[1] Resilience measures can be designed to address infrequently occurring, high-consequence events that apply stress to a system over a large scale, such as disruptions to electric supply resulting from extreme weather events such as hurricanes. Grid modernization activities cite resilience (sometimes called resiliency) as a key electric power grid characteristic to be improved or maximized, and so it is crucial for the development of resilient grid architectures that the concept of grid resilience be clear and quantifiable.[2] As described in *Electric Grid Resilience and Reliability for Grid Architecture*[3] at page 3:

> A key concept here is that resilience is *an intrinsic characteristic of a grid* or portion of a grid. A perfectly resilient grid would not experience outages and so any definition or metric that is based on measuring outage frequencies, times, extents, or impacts on customers or systems does not get

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[1] *See* https://www.nrel.gov/resilience-planning-roadmap/pdfs/defining-resilience-exercise.pdf.

[2] *See* https://gridarchitecture.pnnl.gov/media/advanced/Electric_Grid_Resilience_and_Reliability_v4.pdf. JD Taft, Ph.D., March 2018, prepared for the U.S. Department of Energy by Pacific Northwest National Laboratory under Contract DE-AC05-76RL01830 at page 1.

[3] *Id.* at page 3.

> at the essence of resilience. Resilience applies to the grid under stress: how it resists losing capabilities or gracefully degrades is the essence of resilience. This explains why reliability measures are not useful for quantifying resilience. Resilience is in large part about what does **not** happen. (Emphasis in original.)

Q. PLEASE DISCUSS THE CONCEPT OF "RELIABILITY".

A. The term "reliability" refers to maintaining the delivery of electric power when there is "routine uncertainty in operating conditions" according to the DOE's Grid Modernization Laboratory Consortium.[4] There have been developed an array of well-defined, reported metrics for the bulk power system (e.g., loss of load expectation), and electricity distribution system (e.g., SAIDI[5], SAIFI[6], and CAIDI[7]) to measure reliability. As noted in a May 2, 2018 report concerning *Electric Reliability and Power System Resilience* at page 2, prepared for the Congressional Research Service[8]:

> In the United States, there are two main indices used to measure reliability. The system average interruption duration index (SAIDI) represents *the average amount of time per year that power supply to a customer is interrupted*, expressed in minutes per customer per year. The system average interruption frequency index (SAIFI) represents *the average number of times per year that the supply to a customer is interrupted*, expressed as interruptions per customer per year. However, there is a lack of consistency in how the inputs to these indices are measured, since some jurisdictions consider storm-related outages as "extreme" or unusual events, and thus do not include these in power outage statistics. (Emphasis in original.)

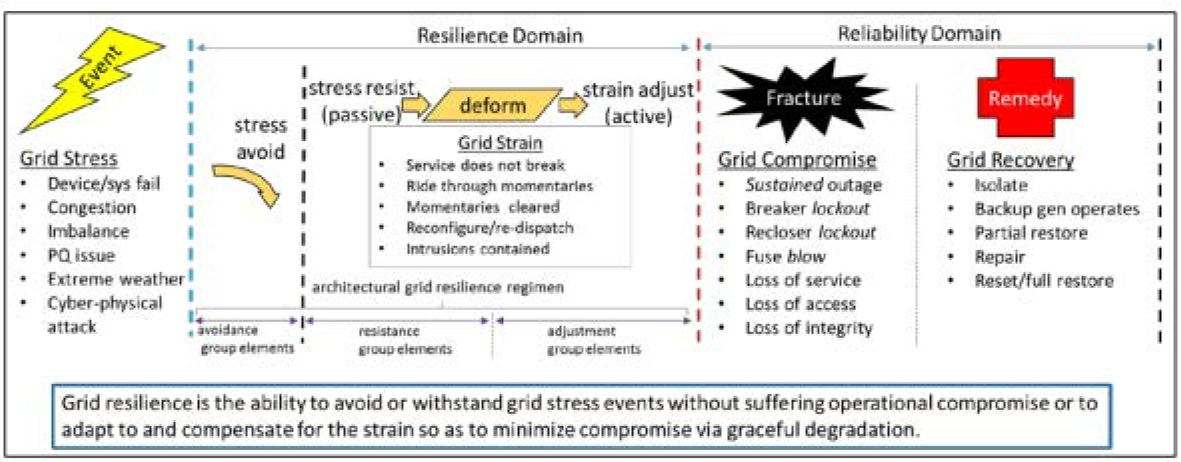
[4] *See* https://gmlc.doe.gov/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf.
[5] System Average Interruption Duration Index (SAIDI), which is stated in minutes per customer, and is commonly reported with and without major events, such as severe storms.
[6] System Average Interruption Frequency Index (SAIFI)
[7] Customer Average Interruption Duration Index (CAIDI) stated in hours per customer
[8] https://www.everycrsreport.com/files/20180502_IN10895_b74bbaf13d1c87cf3bcd377022a1596667834782.pdf, accessed on May 15, 2020.

As stated in Electric Grid Resilience and Reliability for Grid Architecture[9] at page 3:

> Reliability on the other hand, is a measure of *behavior once resilience has broken.* Standard reliability metrics fall into two categories: frequency indices (CAIFI, SAIFI, etc.) and duration indices (CAIDI, SAIDI, etc.). Frequency indices are very roughly related to resilience in the sense that they reflect to some degree how often resilience is broken (but in a non-normalized fashion, making them unusable as resilience measures). Duration indices measure how well a utility responds to broken resilience (also in a non-normalized fashion). This is why recovery, as mentioned in the EPRI resilience definition, actually belongs in the reliability domain.
> The dividing line is clear: for electricity delivery, the start of a sustained outage is the transition point from the domain of resilience to the domain of reliability. An understanding of this concept is necessary for the development of resilient grid architectures.

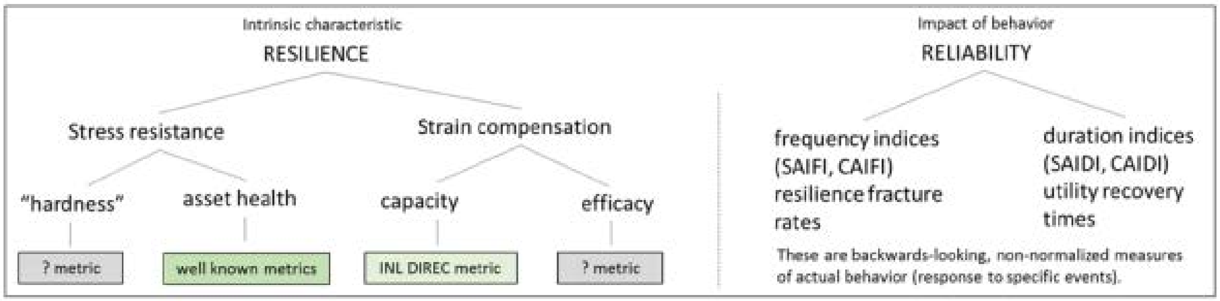
The following diagrams, from pages 3 and 7 of *Electric Grid Resilience and Reliability for Grid Architecture*, respectively, may be helpful in illustrating the relationship and distinguishing factors between the concepts of resilience and reliability:

Figure 1: Resilience and Reliability Domains



[9] *Supra* https://gridarchitecture.pnnl.gov/media/advanced/Electric_Grid_Resilience_and_Reliability_v4.pdf. JD Taft, Ph.D., March 2018, prepared for the U.S. Department of Energy by Pacific Northwest National Laboratory under Contract DE-AC05-76RL01830.

Figure 2: Resilience and Reliability Metrics Taxonomies



Q. WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN RESILIENCY AND RELIABILITY IN EVALUATING UTILITY-PROPOSED SPP INVESTMENTS?

A. Utility proposals to regulators for resilience spending are growing as indicated by the SPP proposals filed by Gulf and other Florida electric utilities. It will, therefore, be important to develop standards to evaluate whether the SPP proposals being made by Gulf and the other Florida electric utilities are cost justified. Standards will be needed to evaluate the value and cost-effectiveness of the utility proposed SPP programs and how they differ from traditional reliability investments that would be included and recovered in utility base rates. Using traditional reliability measures to evaluate utility proposed system hardening expenditures to improve resiliency may not be adequate. As noted above, resilience and reliability are distinguishable concepts and the expenditures to address improvements in each would appear to require their own specialized evaluation criteria. There is not yet a clear and widely accepted "value of resilience" metric, so appropriate evaluation standards will need to be developed in the initial reviews of utility SPP proposals. Moreover, while traditional measurements of reliability have been in use for many years and are widely accepted, there are not yet widely accepted standards for measuring resiliency, measurements for reliability related to resiliency, or widely accepted standards for determining the value of system hardening expenditures intended to improve resiliency. Without such criteria, expenditures may be undertaken by the utility for SPP programs that are not cost effective or do not have a favorable cost-benefit ratio.

III. PRINCIPLES TO BE APPLIED WHEN REVIEWING GULF'S PROPOSED SPP

Q. HAVE YOU IDENTIFIED A SET OF RECOMMENDED PRINCIPLES THAT SHOULD BE APPLIED WHEN REVIEWING GULF'S (AND THE OTHER FLORIDA ELECTRIC UTILITIES') PROPOSED SPP EXPENDITURES?

A. Yes. Working in conjunction with the OPC and various other OPC experts, I have identified the following principles that should be applied when reviewing utility proposed SPP expenditures to ensure that the approved projects meaningfully improve resiliency and reliability, are cost-effective, and minimizes adverse customer rate impacts:

1) determine standard resiliency and reliability metrics baselines to assess improvements from SPP projects;

2) determine consistent cutoff resiliency and reliability metrics that would apply to and limit SPP projects;

3) ensure that the SPP projects are incremental and do not include projects for which costs are currently being recovered through base rates or other surcharges;

4) insist on clearly defined and verifiable cost/benefit analyses and metrics to ensure that customers obtain beneficial value for discretionary investments;

5) determine consistent cutoff cost/benefit metrics that would apply to any proposed SPP projects;

6) determine standard revenue requirement and rate impact methodologies;

7) determine consistent cutoff revenue requirement metrics to limit SPP projects, e.g., limit the effect on overall rates to the rate of inflation or some other benchmark;

8) ensure that the utility is held accountable for the assumptions used to justify the SPP projects based on actual improvements in reliability metrics and reductions in costs, among others;

9) ensure that savings in expenses from the SPP projects are captured as an offset to the incremental costs included in the SPP Cost Recovery Clause ("SPPCRC");

10) ensure that the decrements in revenue requirements as the result of declining cost curves on SPP projects already included in base rates or other surcharges are captured as an offset to the incremental SPP expenditures that would be recovered in the SPPCRC; and

11) establish clear criteria for determining whether and when each utility's resiliency and reliability improvement objectives have been attained.

12) ensure that the SPP is not approved for prudency until it can be determined that resiliency and reliability improvement objectives have been obtained including but not limited to cost-effectiveness and rate impact as required by Rule 25.6.030, F.A.C.,

Q. IS ANOTHER WITNESS FOR THE OPC ADDRESSING SPECIFICS ABOUT SOME OF THESE PRINCIPLES AND HOW THEY SHOULD BE APPLIED TO THE SPP EXPENDITURE PROPSALS OF GULF?

A. Yes. OPC witness Kevin Mara's Direct Testimony provides additional specifics about some of these principles and how they should be applied to the SPP expenditure proposals of Gulf.

IV. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I agree generally that the public could benefit from improvements in grid resiliency and reliability, but would caution that the improvements made should be cost-justified. I agree that there may be merit in selective and cost-effective system hardening and resiliency enhancing expenditures. However, prior to approving utility SPP spending proposals, the Commission must clearly define performance metrics and formulations for cost-benefit analyses. Rather than proceeding apace with accelerated investments that have not been adequately cost-justified, the Commission should require the utilities in the state, such as Gulf, to provide adequate cost-justification before additional investments in grid resiliency are approved for rate recovery or charged to ratepayers. In addition, there are concerns regarding whether SPP surcharge recovery is necessary or appropriate for Gulf for various types of proposed SPP expenditures, such as vegetation management, which traditionally and appropriately has been addressed and the costs recovered through base rates. A clear and specific delineation between (1) base rate recoverable and (2) SPP surcharge recoverable expenditures is needed to facilitate accounting and auditing and prevent abuse and double-recovery. Gulf's experience suggests that enhanced vegetation management costs could be effectively accommodated in the context of a traditional base rate case.

Gulf's SPP expenditure proposals fail to link the costs to clear and verifiable resilience and reliability performance indicators. As a result, Gulf's proposal would assure investors of earnings on investments and recovery of certain specific O&M expenses between rate cases, but customers would be left with the risk and burden of having inadequate or unquantifiable benefits relating to SPP expenditures for which they will be paying. Once the SPP expenditures have been made, documenting imprudence, inefficiency or lack of adequate cost-benefit from such expenditures after the fact is a burden that should not be placed on ratepayers and their representatives. I would thus urge caution and require further cost-benefit analyses for Gulf's SPP projects, including a clear delineation of the expected improvements in resiliency and reliability and a clear method for how these will be measured, prior to authorizing and having the utility embark upon what could be an unjustifiably costly endeavor to enhance system resiliency.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Ralph Smith for Docket No. 20200071-EI was inserted.)

DIRECT TESTIMONY

OF

RALPH SMITH

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

20200071-EI

I. INTRODUCTION

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

A. My name is Ralph Smith. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan, 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, ("Larkin") is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?

A. Yes, I have testified before the Florida Public Service Commission ("PSC" or "Commission") previously. I have also testified before several other state regulatory commissions.

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel ("OPC") to review Florida Power & Light's ("FPL" or "Company") proposed 2020-2029 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 expert opinion regarding issues raised in FPL's proposed 2020-2029 Storm Protection Plan.

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

A. I reviewed the Company's filing, including the direct testimony and exhibits. I also reviewed the Company's responses to OPC's discovery, the Company's responses to PSC

Staff's discovery, and other materials pertaining to the SPP and its impacts on the Company. In addition, I reviewed Rule 25-6.030, Florida Administrative Code ("F.A.C."), concerning approval of a Transmission and Distribution Storm Protection Plan that covers a utility's immediate 10-year planning period.

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

A. I first discuss Rule 25-6.030, F.A.C., and the concept of "resiliency" and distinguish the concepts of "resiliency" and "reliability". I then discuss principles I applied when reviewing FPL'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 each SPP under the statutes and rules governing the SPPs.

II. <u>THE CONCEPTS OF "RESILIENCY" AND "RELIABILITY"</u>

Q. PLEASE DISCUSS RULE 25-6.030, F.A.C.

A. Rule 25-6.030, F.A.C., provides that each utility must file an updated SPP at least every three years that covers the utility's immediate ten-year planning period. Rule 25-6.030, F.A.C., also specifies the information to be included in each utility's SPP. The Florida Legislature directed the Commission to adopt rules to specify the elements that must be included in each utility's SPP. The Florida Legislature found that it was in the State's interest to "strengthen electric utility infrastructure to withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management," and for each electric utility to "mitigate restoration costs and outage times to utility customers when developing transmission and distribution storm protection plans."

Section 366.96(1)(c) and (e), F.S. These objectives of mitigating restoration costs and outage times by strengthening electric utility infrastructure to withstand extreme weather events appear to relate to resiliency, which, as explained below, should be distinguished from reliability, for developing specific criteria to be applied in evaluating utility proposed SPP expenditures.

Q. PLEASE DISCUSS THE CONCEPT OF "RESILIENCY".

A. The term "resilience" means the ability to prepare for and adapt to changing conditions, and withstand and recover rapidly from disruptions.[1] Resilience measures can be designed to address infrequently occurring, high-consequence events that apply stress to a system over a large scale, such as disruptions to electric supply resulting from extreme weather events such as hurricanes. Grid modernization activities cite resilience (sometimes called resiliency) as a key electric power grid characteristic to be improved or maximized, and so it is crucial for the development of resilient grid architectures that the concept of grid resilience be clear and quantifiable.[2] As described in *Electric Grid Resilience and Reliability for Grid Architecture*[3] at page 3:

> A key concept here is that resilience is *an intrinsic characteristic of a grid* or portion of a grid. A perfectly resilient grid would not experience outages and so any definition or metric that is based on measuring outage frequencies, times, extents, or impacts on customers or systems does not get at the essence of resilience. Resilience applies to the grid under stress: how it resists losing capabilities or gracefully degrades is the essence of resilience. This explains why reliability measures are not useful for quantifying resilience. Resilience is in large part about what does **not** happen. (Emphasis in original.)

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[1] See, https://www.nrel.gov/resilience-planning-roadmap/pdfs/defining-resilience-exercise.pdf.

[2] See, https://gridarchitecture.pnnl.gov/media/advanced/Electric_Grid_Resilience_and_Reliability_v4.pdf. JD Taft, Ph.D., March 2018, prepared for the U.S. Department of Energy by Pacific Northwest National Laboratory under Contract DE-AC05-76RL01830 at page 1.

[3] *Id.* at page 3.

Q. PLEASE DISCUSS THE CONCEPT OF "RELIABILITY"

A. The term "reliability" refers to maintaining the delivery of electric power when there is "routine uncertainty in operating conditions" according to the DOE's Grid Modernization Laboratory Consortium.[4] There have been developed an array of well-defined, reported metrics for the bulk power system (e.g., loss of load expectation), and electricity distribution system (e.g., SAIDI[5], SAIFI[6], and CAIDI[7]) to measure reliability. As noted in a May 2, 2018 report concerning *Electric Reliability and Power System Resilience* at page 2, prepared for the Congressional Research Service[8]:

> In the United States, there are two main indices used to measure reliability. The system average interruption duration index (SAIDI) represents *the average amount of time per year that power supply to a customer is interrupted*, expressed in minutes per customer per year. The system average interruption frequency index (SAIFI) represents *the average number of times per year that the supply to a customer is interrupted*, expressed as interruptions per customer per year. However, there is a lack of consistency in how the inputs to these indices are measured, since some jurisdictions consider storm-related outages as "extreme" or unusual events, and thus do not include these in power outage statistics. (Emphasis in original.)

As stated in Electric Grid Resilience and Reliability for Grid Architecture[9] at page 3:

> Reliability on the other hand, is a measure of *behavior once resilience has broken.* Standard reliability metrics fall into two categories: frequency indices (CAIFI, SAIFI, etc.) and duration indices (CAIDI, SAIDI, etc.). Frequency indices are very roughly related to resilience in the sense that they reflect to some degree how often resilience is broken (but in a non-normalized fashion, making them unusable as resilience measures). Duration indices measure how well a utility responds to broken resilience

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[4] See, https://gmlc.doe.gov/sites/default/files/resources/GMLC1%201 Reference Manual2%201final2017 06 01 v4 wPNNLNo 1.pdf.

[5] System Average Interruption Duration Index (SAIDI), which is stated in minutes per customer, and is commonly reported with and without major events, such as severe storms.

[6] System Average Interruption Frequency Index (SAIFI)

[7] Customer Average Interruption Duration Index (CAIDI) stated in hours per customer

[8] https://www.everycrsreport.com/files/20180502_IN10895_b74bbaf13d1c87cf3bcd377022a1596667834782.pdf, accessed on May 15, 2020.

[9] *Supra* https://gridarchitecture.pnnl.gov/media/advanced/Electric Grid Resilience and Reliability v4.pdf. JD Taft, Ph.D., March 2018, prepared for the U.S. Department of Energy by Pacific Northwest National Laboratory under Contract DE-AC05-76RL01830.

(also in a non-normalized fashion). This is why recovery, as mentioned in the EPRI resilience definition, actually belongs in the reliability domain. The dividing line is clear: for electricity delivery, the start of a sustained outage is the transition point from the domain of resilience to the domain of reliability. An understanding of this concept is necessary for the development of resilient grid architectures.

The following diagrams, from pages 3 and 7 of *Electric Grid Resilience and Reliability for Grid Architecture*, respectively, may be helpful in illustrating the relationship and distinguishing factors between the concepts of resilience and reliability:

Figure 1: Resilience and Reliability Domains

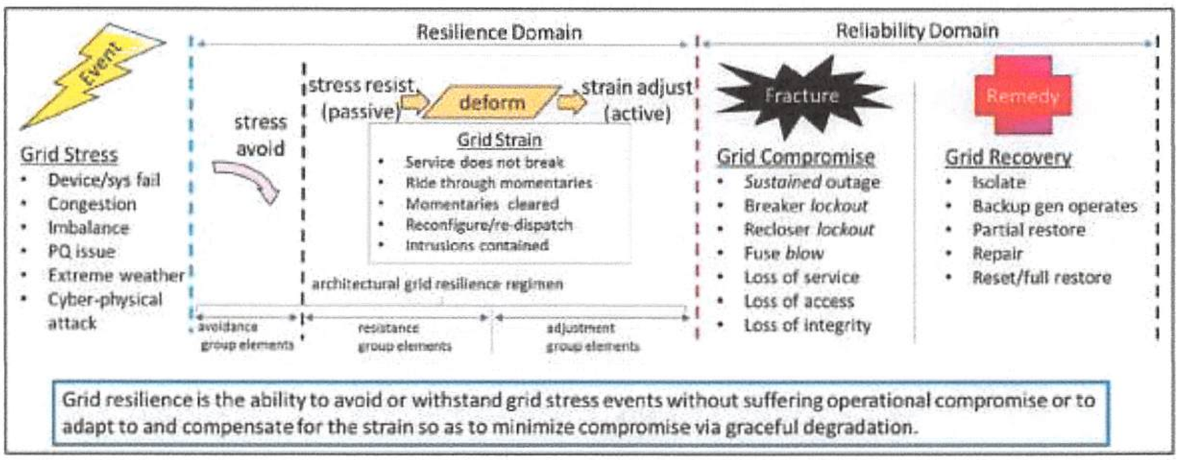
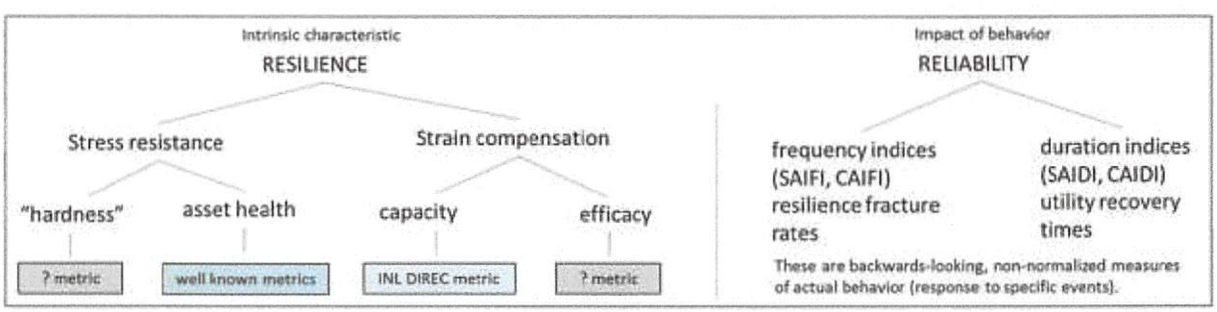


Figure 2: Resilience and Reliability Metrics Taxonomies



Q. WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN RESILIENCY AND RELIABILITY IN EVALUATING UTILITY-PROPOSED SPP INVESTMENTS?

A. Utility proposals to regulators for resilience spending are growing as indicated by the SPP proposals filed by FPL and other Florida electric utilities. It will, therefore be important to develop standards to evaluate whether the SPP proposals being made by FPL and the other Florida electric utilities are cost justified. Standards will be needed to evaluate the value and cost-effectiveness of the utility proposed SPP programs and how they differ from traditional reliability investments that would be included and recovered in utility base rates. Using traditional reliability measures to evaluate utility proposed system hardening expenditures to improve resiliency may not be adequate. As noted above, resilience and reliability are distinguishable concepts and the expenditures to address improvements in each would appear to require their own specialized evaluation criteria. There is not yet a clear and widely accepted "value of resilience" metric, so appropriate evaluation standards will need to be developed in the initial reviews of utility SPP proposals. Moreover, while traditional measurements of reliability have been in use for many years and are widely-accepted, there are not yet widely-accepted standards for measuring resiliency, measurements for reliability related to resiliency or widely-accepted standards for determining the value of system hardening expenditures intended to improve resiliency. Without such criteria, expenditures may be undertaken by the utility for SPP programs that are not cost effective or do not have a favorable cost-benefit ratio.

III. PRINCIPLES TO BE APPLIED WHEN REVIEWING FPL'S PROPOSED SPP

Q. HAVE YOU IDENTIFIED A SET OF RECOMMENDED PRINCIPLES THAT SHOULD BE APPLIED WHEN REVIEWING FPL'S (AND THE OTHER FLORIDA ELECTRIC UTILITIES') PROPOSED SPP EXPENDITURES?

A. Yes. Working in conjunction with the OPC and various other OPC experts, I have identified the following principles that should be applied when reviewing utility proposed SPP expenditures to ensure that the approved projects meaningfully improve resiliency and reliability, are cost-effective, and minimizes adverse customer rate impacts:

1) determine standard resiliency and reliability metrics baselines to assess improvements from SPP projects;

2) determine consistent cutoff resiliency and reliability metrics that would apply to and limit SPP projects;

3) ensure that the SPP projects are incremental and do not include projects for which costs are currently being recovered through base rates or other surcharges;

4) insist on clearly defined and verifiable cost/benefit analyses and metrics to ensure that customers obtain beneficial value for discretionary investments;

5) determine consistent cutoff cost/benefit metrics that would apply to any proposed SPP projects;

6) determine standard revenue requirement and rate impact methodologies;

7) determine consistent cutoff revenue requirement metrics to limit SPP projects, e.g., limit the effect on overall rates to the rate of inflation or some other benchmark;

8) ensure that the utility is held accountable for the assumptions used to justify the SPP projects based on actual improvements in reliability metrics and reductions in costs, among others;

9) ensure that savings in expenses from the SPP projects are captured as an offset to the incremental costs included in the SPP Cost Recovery Clause ("SPPCRC");

10) ensure that the decrements in revenue requirements as the result of declining cost curves on SPP projects already included in base rates or other surcharges are captured as an offset to the incremental SPP expenditures that would be recovered in the SPPCRC;

11) establish clear criteria for determining whether and when each utility's resiliency and reliability improvement objectives have been attained; and

12) ensure that the SPP is not approved for prudency until it can be determined that resiliency and reliability improvement objectives have been obtained including but not limited to cost-effectiveness and rate impact as required by Rule 25.6.030, F.A.C.

Q. IS ANOTHER WITNESS FOR THE OPC ADDRESSING SPECIFICS ABOUT SOME OF THESE PRINCIPLES AND HOW THEY SHOULD BE APPLIED TO THE SPP EXPENDITURE PROPSALS OF FPL?

A. Yes. OPC witness Kevin Mara's Direct Testimony provides additional specifics about some of these principles and how they should be applied to the SPP expenditure proposals of FPL.

IV. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I agree generally that the public could benefit from improvements in grid resiliency and reliability, but would caution that the improvements made should be cost-justified. I agree that there may be merit in selective and cost-effective system hardening and resiliency enhancing expenditures. However, prior to approving utility SPP spending proposals, the Commission must clearly define performance metrics and formulations for cost-benefit analyses. Rather than proceeding apace with accelerated investments that have not been adequately cost-justified, the Commission should require the utilities in the state, such as FPL, to provide adequate cost-justification before additional investments in grid resiliency are approved for rate recovery or charged to ratepayers. In addition, there are concerns regarding whether SPP surcharge recovery is necessary or appropriate for FPL for various types of proposed SPP expenditures, such as vegetation management, which traditionally and appropriately has been addressed and the costs recovered through base rates. A clear and specific delineation between (1) base rate recoverable and (2) SPP surcharge recoverable expenditures is needed to facilitate accounting and auditing and prevent abuse and double-recovery. FPL's experience suggests that enhanced vegetation management costs could be effectively accommodated in the context of a traditional base rate case.

FPL's SPP expenditure proposals fail to link the costs to clear and verifiable resilience and reliability performance indicators. As a result, FPL's proposal would assure investors of earnings on investments and recovery of certain specific O&M expenses between rate cases, but customers would be left with the risk and burden of having inadequate or unquantifiable benefits relating to SPP expenditures for which they will be paying. Once the SPP expenditures have been made, documenting imprudence, inefficiency or lack of adequate cost-benefit from such expenditures after the fact is a burden that should not be placed on ratepayers and their representatives. I would thus urge caution and require further cost-benefit analyses for FPL's SPP projects, including a clear delineation of the expected improvements in resiliency and reliability and a clear method for how these will be measured, prior to authorizing and having the utility embark upon what could be an unjustifiably costly endeavor to enhance system resiliency.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Lisa V. Perry for Docket Nos. 20200067-EI, 20200069-EI, 20200070-EI and 20200071-EI was inserted.)

I. Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Lisa V. Perry. My business address is 2608 SE J Street, Bentonville, AR 72716. I am employed by Walmart Inc. ("Walmart") as Senior Manager, Energy Services.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THESE DOCKETS?

A. I am testifying on behalf of Walmart.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I received a J.D. in 1999 and an LL.M. in Taxation in 2000 from the University of Florida, Levin College of Law. From 2001 to 2019, I was in private practice, emphasizing in Energy Law from 2007 to 2019. My practice included representing a large commercial client before utility regulatory commissions in Colorado, Texas, New Mexico, Arkansas, and Louisiana in matters ranging from general rate cases to renewable energy programs. I joined the energy department at Walmart in September 2019. My Witness Qualifications Statement is attached as Exhibit LVP-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. No, I have not.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes, I have submitted testimony in Arkansas, Louisiana, Oklahoma, South Carolina, Texas, and Virginia. I have also provided legal representation for customer stakeholders before the state regulatory commissions of Colorado, Texas, Arkansas, Louisiana, and New Mexico in the cases listed under "Commission Dockets" in Exhibit LVP-1.

Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibit listed in the Table of Contents.

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS IN FLORIDA.

A. As shown on Walmart's website, Walmart operates 384 retail units and eight distribution centers and employs over 106,000 associates in Florida. In fiscal year ending 2020, Walmart purchased $7.4 billion worth of goods and services from Florida-based suppliers, supporting over 87,000 supplier jobs.[1]

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to offer insight with regard to the petitions listed below from the perspective of a large energy customer who provides critical services

[1] http://corporate.walmart.com/our-story/locations/united-states/florida

and supplies during extreme weather events in the state of Florida. The Commission consolidated the following petitions in which utilities are seeking approval of their respective Transmission and Distribution ("T&D") Storm Protection Plans ("SPPs"):[2]

(1) Tampa Electric Company's ("TECO") Petition for Approval of Storm Protection Plan, filed April 10, 2020, Docket No. 20200067-EI;

(2) Florida Public Utilities, Docket No. 20200068-EI (this docket was subsequently closed by the Commission on April 6, 2020; *see* Order No. PSC-2020-0097-PCO-EI issued April 6, 2020);

(3) Duke Energy Florida, LLC's ("DEF") Petition for Approval of 2020-2029 Storm Protection Plan, filed April 10, 2020, Docket No. 20200069-EI;

(4) Petition of Gulf Power Company ("Gulf") for Approval of the 2020-2029 Storm Protection Plan, filed April 10, 2020, Docket No. 20200070-EI; and

(5) Petition of Florida Power & Light Company ("FPL") for Approval of the 2020-2029 Storm Protection Plan, filed April 10, 2020, Docket No. 20200071-EI.

The above-listed petitions are collectively referred to in my testimony as the "Petitions" and the respective utilities are referred to collectively as the "Utilities."

[2] *See* Order No. PSC-2020-0073-PCO-EI issued April 6, 2020, Docket Nos. 20200067-EI, 20200068-EI, 20200069-EI, 20200070-EI, and 20200071-EI.

Q. ARE OTHER WITNESSES FILING TESTIMONY ON BEHALF OF WALMART?

A. Yes, Steve Chriss, Director, Energy Services for Walmart is also filing testimony in these Dockets on behalf of Walmart. Mr. Chriss addresses the proposed illustrative rate designs included in the Utilities' filings.

Q. PLEASE SUMMARIZE WALMART'S RECOMMENDATIONS TO THE COMMISSION.

A. The Commission should require the Utilities to work with Walmart and other interested stakeholders during the interim period before the Utilities' next required updated SPPs[3] to develop ways in which customer-sited generation can be utilized as part of the SPPs in order to strengthen the T&D systems and provide customers with lower restoration costs, shorter outage periods, and more reliable electric service overall.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE UTILITIES INDICATE WALMART'S SUPPORT?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

[3] The Utilities are required to file an updated SPP at least every 3 years. *See* FLA. STAT. § 366.96(6); *see also* FLA. ADMIN. CODE ANN. r. 25-6.030(1) (2019).

III. Governing Statute and Administrative Rule

Q. WHAT IS YOUR UNDERSTANDING OF THE PETITIONS?

A. As required by a mandate set forth in Section 366.96 of the Florida Statutes and Rule 25-6.030 of the Florida Administrative Code, the Utilities filed their respective Petitions in order to seek approval of their SPPs.

Q. COULD YOU PLEASE PROVIDE MORE INFORMATION ABOUT THIS MANDATE?

A. On June 27, 2019, Florida Governor Ron DeSantis signed into law Senate Bill 796: Public Utility Storm Protection Plans, which is codified in the Florida Statutes at Section 366.96 ("SPP Statute"). The SPP Statute requires Florida's regulated utilities to file a 10-year forward looking plan and to update these plans at least every 3 years. *See* FLA. STAT. § 366.96(3) and § 366.96(6) (2019). This plan is described in the SPP Statute as a "transmission and distribution storm protection plan" that explains the utility's systematic approach to achieving certain objectives set forth by the legislature. *Id.* at 366.96(3).

Q. WHAT ARE THE LEGISLATURE'S STATED OBJECTIVES?

A. In its drafting of the SPP Statute, the Florida Legislature described its objectives as reducing restoration costs and outage times that are associated with extreme weather events and enhancing reliability. *See id.* at 366.96(3). These objectives were declared to be in the state's interest. *See id.* at 366.96(1)(e). The Legislature goes on to point out that strengthening a utility's transmission and distribution infrastructure from these weather events not only reduces the cost to restore power, but also improves service reliability for customers overall. *Id.* at (1)(d).

Q. DID THE LEGISLATURE PROVIDE THE COMMISSION WITH ANY GUIDANCE WHEN REVIEWING THE UTILITIES' SPPs?

A. Yes, it did. When an SPP is filed with the Commission, it is the Commission's responsibility to determine whether it is in the public interest to approve, approve with modifications, or to deny the SPP. *Id.* at 366.96(5). When making this determination, there are certain factors that the Legislature requires the Commission to consider, including the extent to which the SPP will reduce restoration costs and power outage times, how practical a certain location selected for T&D infrastructure is relative to the utility's service territory, the cost/benefit to customers, and the impact on customers' bills. *See id.* at 366.96(4)(a)-(d).

Q. ARE THE UTILITIES' SPPs SUBJECT TO ANY REGULATIONS IN ADDITION TO THE SPP STATUTE?

A. Yes. To further its objectives, the Legislature tasked the Commission with adopting rules to implement and administer the SPP Statute, which the Commission did when it promulgated Rule 25-6.030 of the Florida Administrative Code ("SPP Rule"). *See id.* at 366.96(11).

III. Strengthening the Utilities' T&D Systems with Customer-Sited Generation

Q. WHAT IS THE OVERALL GOAL OF THE SPP STATUTE AND SPP RULES?

A. When considering the language of the SPP Statute and the SPP Rule, the overall goal of the Legislature and the Commission becomes clear – make the T&D systems more reliable and resilient in order to reduce the frequency and duration of power outages from hurricanes or other major storms in the most cost efficient manner. To achieve this goal, the Legislature rightfully focuses on a utility's T&D facilities, which tend to be the most vulnerable parts of a utility's overall system during severe weather events.

Q. DO THE UTILITIES ALSO SEEK TO ACHIEVE THESE SAME GOALS OR OBJECTIVES THROUGH THEIR SPPs?

A. Based upon the assertions made in the Utilities' Petitions and supporting testimony, this appears to be the case. *See, e.g.,* Petition of Gulf Power Company for Approval of the 2020-2029 Storm Protection Plan filed April 10, 2020, Docket No. 20200070-EI, page 13, paragraph 32 (concluding that Gulf's SPP provides a systematic approach to achieving the legislative objectives of reducing restoration costs and outage times due to extreme weather and enhancing reliability).

Q. ARE THERE WAYS IN WHICH CUSTOMERS CAN HELP A UTILITY STRENGTHEN ITS DISTRIBUTION SYSTEM DURING A SEVERE WEATHER EVENT?

A. Absolutely. Developing technologies and operational sophistication have positioned large commercial customers, like Walmart, to be a valuable resource for utilities, first responders, and the community at large during critical weather events. Specifically, holistic planning that includes distributed energy resources ("DERs") allows a utility to restore power, reduce outage times, and improve service reliability more efficiently and cost effectively.

Q. WHAT IS A DER?

A. A DER, as defined by the National Association of Regulatory Utility Commissioners ("NARUC"), is:

> a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load.

See Kiera Zitelman*, Advancing Electric System Resilience with Distributed Energy Resources: A Review of State Policies*, NARUC, April 2020, at 6 ("NARUC DER Article"). In other words, DERs are customer-cited sources of power or storage that typically connect to and/or operate independent of the grid. Examples include customer-sited generation, energy storage, demand response, electric vehicles, microgrids, and energy efficiency.

Q. WHAT TYPE OF SUPPORT CAN DERs PROVIDE DURING EXTREME WEATHER EVENTS?

A. As discussed at some length in the NARUC DER Article, one of the many benefits of DERs is helping to improve system reliability and resilience by providing dispatchable generation resources that supply power when electricity from the utility is no longer available. This type of generation resource can operate independently, for example, by providing back-up generation for a large commercial and industrial ("C&I") customer, work in conjunction with other generation resources or storage located within a defined electrical boundary, also known as a microgrid,[4] and/or inject power back onto the grid.

Q. HOW DOES A CUSTOMER-SITED DISPATCHABLE GENERATION RESOURCE HELP REDUCE RESTORATION COSTS DURING EXTREME WEATHER EVENTS?

A. A customer-sited dispatchable generation resource, whether operating alone or within a microgrid, may help reduce restoration costs by essentially allowing one or more customers to be self-sufficient during the restoration process. Restoring power after a severe weather event like a hurricane is likely an extensive process that requires the utility to prioritize areas that are impacted by an outage and dispatch their field personnel accordingly. If a portion of the utility's large customers are being supplied by power independently, it allows the utility to focus its efforts on other areas. Providing a utility with this type of "breathing room" gives the utility flexibility to mobilize more cost-efficient restoration plans that may not otherwise be available.

[4] The Department of Energy defines a microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid." These multiple DERs may include small fossil generation, solar photovoltaic, and storage. *See* NARUC DER Article at 17.

Q. HOW DOES A CUSTOMER-SITED DISPATCHABLE GENERATION RESOURCE ENHANCE RELIABILITY DURING EXTREME WEATHER EVENTS?

A. Speaking from the perspective of a large commercial customer who has extensive operational experience during and after hurricanes in Florida, it is Walmart's experience that utility personnel who are responsible for visiting sites and restoring the T&D systems require various supplies ranging from water to cell phones. It is important to Walmart that it has the operational ability to serve these needs in order to ensure that field personnel have what is required to restore the T&D systems and turn the lights back on for everyone.

Moreover, it is not just utility employees who turn to Walmart and other large commercial customers for necessary supplies. Walmart strives to be a leader in caring for the needs of communities during times of tremendous hardship, like a hurricane or other severe weather event. This includes providing supplies to first responders, shelters, and citizens who live in the area and need every day basics to live. Ensuring that utility customers who provide critical services and supplies can remain open and operational during and after a severe weather event enables that area to restore faster, which in turn, makes the T&D systems more reliable and resilient.

Q. WHAT IS WALMART'S RECOMMENDATION TO THE COMMISSION?

A. Walmart recommends that the Commission should require the Utilities to work with Walmart and other interested stakeholders during the interim period before their next required updated SPPs[5] to develop ways in which customer-sited generation can be utilized as part of the SPP in order to strengthen the T&D systems and provide customers with lower restoration costs, shorter outage periods, and more reliable electric service overall.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[5] The Utilities are required to file an updated SPP at least every 3 years. *See* FLA. STAT. § 366.96(6); *see also* FLA. ADMIN. CODE ANN. r. 25-6.030(1) (2019).

(Whereupon, prefiled rebuttal testimony of Regan B. Haines was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

REGAN B. HAINES

TABLE OF CONTENTS:

INTRODUCTION:

Q. Please state your name, address, occupation, and employer.

A. My name is Regan B. Haines. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Director, Asset Management, Project Management and System Planning.

Q. Are you the same Regan B. Haines who filed direct testimony in this proceeding?

A. Yes, I am.

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

A. The purpose of my rebuttal testimony is to address the direct testimony and exhibits of Steve Chriss and Lisa Perry, both of whom are testifying on behalf of Walmart Incorporated. I will also provide rebuttal testimony to address the deficiencies and misconceptions in the direct testimony and exhibits of Scott Norwood and Lane Kollen, both of whom are testifying on behalf of Florida’s Office of Public Council (“OPC”).

Rebuttal testimony addressing the testimony of OPC’s witnesses Norwood and Kollen is also being submitted by Tampa Electric witnesses A. Sloan Lewis and Jason D. De Stigter. For the sake of brevity, I have omitted from my rebuttal testimony some of the concerns addressed by Ms. Lewis and Mr. De Stigter, and I support their rebuttal testimony on any points they make which are not repeated in my rebuttal testimony.

REBUTTAL TO DIRECT TESTIMONY OF STEVE W. CHRISS AND LISA V. PERRY

Q. Do you have any general comments regarding the overall direct testimony of Mr. Chriss and Ms. Perry?

A. I have no comments regarding Mr. Chriss' testimony but I do disagree with the recommendation made by Ms. Perry in her testimony as I explain below. Tampa Electric is also reserving the right to provide rebuttal on any new topics that may arise in the future.

Q. On Page 4, line 6 of Ms. Perry's testimony, she recommends that the Commission should require the utilities to work with Walmart and other interested stakeholders during the next interim period to develop ways to include customer sited generation as a method to meet the requirements of the SPP, do you agree with this statement?

A. No, I do not agree with Ms. Perry's statement. The company's Storm Protection Plan ("SPP") is designed to achieve the objectives of Section 366.96 of the Florida Statutes and the requirements of Rule 25-6.030, which implements that statute. Neither the Statute nor the Rule requires electric utilities to include customer-sited generation in their storm protection plans. Tampa Electric would, however, be willing to meet with Walmart to discuss individual reliability concerns or options for resiliency as is commonly done with many customers as part of the customer service the company typically provides.

REBUTTAL TO DIRECT TESTIMONY OF SCOTT NORWOOD:

Q. Do you have any general comments regarding the overall direct testimony of Mr. Norwood?

A. Yes, overall Mr. Norwood's testimony inaccurately accuses Tampa Electric of a lack of transparency in the development of the company's proposed SPP. Mr. Norwood's testimony also demonstrates that he does not understand the purpose of the SPP and fails to distinguish between extreme weather resiliency day-to-day or "blue-sky" reliability.

Q. On Page 5, line 17 of his testimony, Mr. Norwood states that the Company barred review of details regarding its Cost Benefit Analysis ("CBA") calculations, is this statement true?

A. No, this statement is false. Tampa Electric provided a high level of transparency regarding the development of the company's SPP through both its initial filing in this proceeding and through the discovery process thus far. The company's filed SPP contains all of the content required by Rule 25-6.030. In addition to the minimum filing requirements, the company also provided an 80 page report from 1898 & Co., the outside consultant that developed the company's cost-benefit analysis, as well as a report from Accenture describing the development of the company's vegetation management program. After filing Tampa Electric's SPP, the company then provided responses to 210 Interrogatories (not including subparts) and 79 Requests for Production of Documents (not including subparts) from OPC. Finally, the company hosted a four-hour open question technical session for Mr. Norwood and other OPC representatives to view the confidential mechanics of 1898 & Co.'s proprietary models and to view how they were utilized to develop the company's cost-benefit analysis.

Q. On Page 5, line 20 of his testimony, Mr. Norwood states that TECO's lack of transparency needlessly complicates the Commission's review and is unusual for an investment of this magnitude, is this statement accurate?

A. No, as I have clearly explained above, the company provided information above and beyond the minimum filing requirements set out in Rule 25-6.030, responded to hundreds of discovery requests, and hosted a technical session to explain 1898 & Co.'s models to OPC. The company's filing and all of its discovery responses are available for review by Commission Staff, and the Commission will have a robust record to review in evaluating Tampa Electric's proposed SPP.

Q. On Page 6, line 18 of his testimony, Mr. Norwood states that the forecasted improvement is relatively small and would likely increase TECO's annual service reliability by less than 0.004 percent, do you agree with this statement?

A. No, I do not agree with this statement and do not know how Mr. Norwood was able to make this determination. Section 366.96 and Rule 25-6.030 require Tampa Electric to develop a plan that will reduce restoration costs and outage times associated with extreme weather and enhance reliability. I believe the programs included in the company’s SPP will certainly accomplish these objectives. While the company did not quantify day-to-day or blue-sky reliability and service level improvements associated with the company’s SPP, these will be a secondary benefit of the company’s plan’s implementation.

Q. On Page 6, lines 21-24 of his testimony, Mr. Norwood states that the SPP is not needed at this time and should be postponed due to the COVID-19 pandemic. Do you agree that the SPP should be postponed?

A. I do not agree that the company’s proposed SPP should be postponed. The company’s proposed SPP is consistent with the Statute and is designed to improve the reliability of electric service by reducing restoration costs and outage times following major weather events is even more critical at this time given the impact of COVID-19 and the number of Floridians unemployed and/or working from home.

Q. On Page 6, lines 21-25 of his testimony, Mr. Norwood states that potentially less costly alternatives to the SPP can be evaluated and the company’s proposed SPP should be delayed, do you agree with this statement?

A. No, I do not agree with Mr. Norwood's statement. The company is constantly reviewing various hardening projects and options and has been doing so since 2006 and believes that the SPP programs proposed represent essential fundamental hardening actions that have been demonstrated and proven effective in improving the resiliency of the power grid by the utilities in the state. This applies to feeder hardening, transmission hardening as well as the need to underground vulnerable overhead distribution facilities and place additional attention on increased vegetation management. In addition, the results of 1898 & Co. budget optimization analysis that was performed was to identify the point of diminishing returns and to consider the very same alternative levels of spending was included in the direct testimony of Jason D. De Stigter as well as in the 1898 & Co. report.

Q. On Page 7, line 1 of his testimony, Mr. Norwood recommends to the Commission that it approve a modified SPP contingent upon filing an updated SPP in 2022, do you agree with his recommendation?

A. No, I do not agree with making modifications to the filed SPP plan. The proposed plan includes storm protection programs designed to reduce storm restoration costs and outage times for the company’s customers when Tampa Electric is impacted by a major storm event. Modifying the plan as suggested by Mr. Norwood will only delay these benefits and create additional risk for our customers.

Q. On Page 11, line 1 through page 12, line 13 of his testimony, Mr. Norwood makes statements that the extreme weather events in the company’s service area are small and because of this, there is only a small potential outage reduction benefit of the SPP, which he states that most TECO customers would probably not notice, do you agree with his assessment?

A. No, I do not agree with this statement. While Tampa Electric has been very fortunate since 2006 regarding the number and severity of the extreme weather events experienced, the average Extreme Weather Event (“EWE”) System Average Interruption Duration Index (“SAIDI”) each year since 2006 as calculated by Mr. Norwood nearly doubles the normal outage time experienced on average each year by our customers. That is significant and would increase drastically if our service territory is impacted by more and/or stronger storms in the future.

It is also misleading to look at System Average Interruption Frequency Index ("SAIFI") for a specific event as it typically reflects the average number of outages experienced by each customer for an entire year. Since Hurricane Irma was the only large storm during the period evaluated by Mr. Norwood, the total SAIFI impact is small on average for that time period but the seven-day restoration effort and nearly $100M in restoration costs due to Hurricane Irma certainly had a significant impact on customers.

Q. On Page 13, line 9 of his testimony, Mr. Norwood makes statements regarding the rate impacts of the company's proposed SPP and asserts that these are incremental, are these statements accurate?

A. No, the company clearly communicated in the SPP that the costs and associated revenue requirements within the plan were based upon a total of all storm protection and prior legacy storm hardening activities which included items within base rates that would never make their way into the Storm Protection Cost Recovery Clause. The rebuttal testimony of A. Sloan Lewis will address this issue as well in her rebuttal response to the testimony of OPC Witness Mr. Lane Kollen, who makes the same inaccurate statement.

Q. On Page 14, line 14 of his testimony, Mr. Norwood makes statements that the company’s CBA is not cost-effective, is this statement accurate?

A. No, it appears that Mr. Norwood did not consider the estimated restoration cost savings from each of the proposed SPP programs in his calculations. The company has provided an estimate of both the restoration cost savings and the quantified, monetized benefits resulting from reduced customer outage time. These were provided as required by the rule but were not used to determine cost effectiveness. The quantified outage time savings benefits were solely used to rank and prioritize projects within each program.

Q. On Page 15, line 10 of his testimony, Mr. Norwood asserts that the company “has not provided details regarding the CBA calculations for proposed SPP programs, as required by Rule 25-6.030(3)(d), F.A.C.” Do you agree with this statement?

A. No, there is no merit to this statement. The company has met all of the requirements of the rule which includes providing a “description of how each proposed storm protection program is designed to enhance the utility’s existing transmission and distribution facilities including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions” and a comparison of the costs and benefits. To meet these requirements, the company acquired assistance from industry consultants with extensive expertise in this area and utilized a robust methodology and model to quantify the restoration cost savings and outage time reduction benefits. Secondly, Mr. Norwood claims “many details regarding the Storm Modeling calculations supporting the forecasted EWE storm impacts on TECO’s system, are not available to OPC or other parties.” Again, the company has met the requirements of the rule and provided an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions. In addition, the company provided a copy of the 72-page report (Appendix F in the filed SPP plan) summarizing the analysis conducted by 1898 & Co. This report fully explains the approach and methodology used for estimating the restoration cost savings and outage time reduction benefits. In addition, the company responded to several hundred discovery requests from the OPC and held a four hour question and answer session with Mr. Norwood and other OPC representatives to demonstrate the model 1898 & Co. utilized, review results, discuss the approach and methodologies and answer all questions posed by Mr. Norwood and the OPC.

Q. On page 17, line 5 of his testimony, Mr. Norwood claims that “the Company did not evaluate or present potentially lower cost alternatives to the $1.92 billion Plan…”. Do you agree with this statement?

A. No. As pointed out in 1898 & Co.’s filed report, Tampa Electric and 1898 & Co. did evaluate various investment levels utilizing a resilience-based planning approach to establish an overall budget level and identify and prioritize resilience investments in the T&D system. This was accomplished by performing a budget optimization analysis, the results of which are shown in Figure 1-2 on Bates stamp page 137 of the filed SPP Plan. The budget optimization analysis was performed in $250 million increments up to $2.5 billion and the figure shows the total lifecycle gross NPV benefit for each budget scenario. The $1.92 billion investment level recommended was identified as prudent level of investment over the next 10 years capturing the hardening projects that meet the objectives of the SPP rule and provide the most value to customers.

Q. On page 17, line 18 of his testimony, Mr. Norwood claims that TECO's CBA for the SPP is flawed because it includes approximately $4 billion of non-electric customer benefits for the purpose of selection and prioritization of programs included in the SPP. Do you agree with this statement?

A. No. First, the $4 billion is not only non-electric customer benefits, it also includes restoration costs savings. Second, the customer benefits portion of the $4 billion is based upon monetizing the CMI reduction for each proposed hardening project using the Department of Energy's Interruption Cost Estimate (ICE) Calculator. This tool is well established and has been used in the industry for quite some time to quantify and monetize the customer benefits from outage time reductions. The company only used this to compare the benefits of projects within an SPP Program to help rank and establish implantation schedules. The monetized customer benefits were not used to cost justify any of the proposed SPP Programs.

Q. On Page 19, line 6 of his testimony, Mr. Norwood states that the company did not evaluate the electric cost benefits of potentially lower cost alternatives to the SPP, is this statement accurate?

A. That statement is not accurate. The company looked at varying levels of activity within each SPP program as well as the benefits associated with varying levels of investment in total. For example, 1898 & Co. modeled different levels of investment for each proposed program as alternatives as well as total plan investment to optimize against the estimated expected benefits. The company also considered various alternatives to some of the proposed programs such as undergrounding transmission and undergrounding distribution feeders, but deemed those to not be as cost effective as the overhead hardening default standard for each. However, the company did not discount the need to underground either transmission or distribution feeders in the future as justified on a case by case basis.

Q. On Page 19, Section V (No line number) of his testimony, Mr. Norwood discusses his experience with how regulatory Commissions evaluate major electric utility investment such as the SPP, do you agree with his opinion?

A. I do not agree that Mr. Norwood's experience with other regulatory Commissions should have any bearing on this docket. Tampa Electric has developed its filed SPP to meet the requirements of Section 366.96 and Rule 25-6.030.

Q. On Page 20, line 3 of his testimony, Mr. Norwood discusses how reliability is measured for electric transmission and distribution customers, do you agree with his assessment?

A. I agree that we have well established reliability metrics in place, including SAIDI and SAIFI, to measure day-to-day or blue-sky reliability of the electric system. For example, SAIDI captures the average outage time for each customer for the year, excluding events such as named storms, while SAIFI captures the average number of outages for each customer for the year, also excluding events such as named storms. However, what Mr. Norwood is missing and fails to address is that the intent of the new Storm Protection Plan legislation and rule is to improve the electric system's resiliency. While the terms reliability and resiliency are often interchanged, they are not the same. Electric reliability is typically defined as dependably delivering quality electricity on a day-to-day basis to customers. While resiliency can be defined as the ability for the electric grid to withstand and recover from extreme events, including severe weather or other natural disasters, as well as cyber and physical threats. Again, reliability and resiliency are not the same, however resiliency does directly impact reliability. While the SPP Programs proposed will certainly have a positive impact on reliability, the company's focus was to improve and increase the electric system's resiliency.

Q. On Page 22, line 12 of his testimony, Mr. Norwood discusses evidence that TECO's customers are happy with the company's reliability performance, do you agree with his assessment?

A. While I agree that Tampa Electric's customers have been satisfied with their day-to-day electric service reliability based on the percentage of customers submitting PSC complaints cited by Mr. Norwood, customers experiencing outages following Hurricane Irma who did not have their power restored for several days were not happy. The objective of the SPP rule is to improve the resiliency of the power grid and to reduce outages, outage times and restoration costs for our customers following major weather events. While the SPP programs proposed will improve day-to-day reliability, it was not the primary purpose of the filed SPP plan.

Q. On Page 23, line 1 of his testimony, Mr. Norwood states that the reliability of the company's system would not be improved that much with the SPP, is this statement accurate?

A. No, as I explained earlier, the objective of the SPP rule is to improve the resiliency of the power grid and to reduce outages, outage times and restoration costs for our customers following major weather events. While the SPP programs proposed will improve day-to-day reliability, it was not the primary purpose of the filed SPP and the company did not attempt to quantify the day-to-day or blue-sky reliability benefits. Mr. Norwood has pointed to historical reliability and outage data for the last ten years as an indicator of the future. Tampa Electric has evaluated several future storm scenarios over the next 50 years and taken a proactive approach, recommending several prudent actions that can be taken to improve the resiliency of the power grid in order to improve electric service to our customers and reduce restoration costs in the future.

Q. On Page 28, Section VII (No line number) of his testimony, Mr. Norwood states his conclusions and recommendations, do you agree with any of his conclusions and recommendations?

A. No, I would not endorse or recommend any of his conclusions or recommendations.

REBUTTAL TO DIRECT TESTIMONY OF LANE KOLLEN:

Q. Do you have any general comments regarding the overall direct testimony of Mr. Kollen?

A. Yes, Mr. Kollen asks the Commission to reject all of the company's SPP projects based upon his misinterpretation of how the company and 1898 & Co. developed the projected cost benefit analysis. It also seems that Mr. Kollen wants the Commission to establish some arbitrary threshold for cost-effectiveness. He first says 100 percent and then changes his threshold to some other defined threshold, such as 50 percent.

Q. On Page 11, line 1 of his testimony, Mr. Kollen states that none of the company's projects were economically justified with a benefit to cost ratio of at least 100 percent and provides benefit to cost ranges from 10 to 90 percent, do you agree with his assessment?

A. No, his assessment is inaccurate. In the company's filed SPP, the company and 1898 & Co. provided projected reductions in restoration costs and projected reductions in customer minutes of interruption as approximate benefits in ranges of percent reduction compared to maintaining the status quo. Mr. Kollen is misinterpreting these values as a benefit to cost ratio.

Q. From the immediate question above, are SPP projects required to have some benefit to cost ratio provided either in 366.96, Rule 25-6.030, or the Order Establishing Procedure for this proceeding?

A. No, the statute and rule require a description of each proposed storm protection program that includes a description of how each proposed storm protection program is designed to enhance the utility's existing transmission and distribution facilities including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions. The rule does not mention a required minimum benefit to cost ratio to be approved.

Q. On Page 12, line 3 of his testimony, Mr. Kollen states that SPP Programs should not be approved if the costs are not economically viable, do you agree with his assessment?

A. No, regarding the SPP, the Governor and Florida Legislature have made it clear that there is a need to further harden and protect the electrical system in Florida from extreme weather events. The economic viability of the proposed SPP investments can only be identified if one could accurately forecast the number and severity of the future storms, we can expect to experience over the next fifty years. Tampa Electric has made the decision to invest proactively in increasing the resiliency of its power grid before we experience a major storm event. The company believes these investments are prudent given the Legislature's express desire to reduce restoration costs and outage times for our customers over the next 50 years.

Q. On Page 14, lines 7-9 of his testimony, Mr. Kollen states that "TECO failed to include additional savings related to "normal operation" and "normal weather", which it refers to as "blue-sky" days, except for the savings in vegetation management expense it claims is reflected in the Accenture analysis and qualifications." Do you agree with this statement?

A. No. In accordance with the 2020 Settlement Agreement, the company will be carrying out a one-time base rate reduction and consequently recover all SPP-related expenses through the Storm Protection Plan Cost Recovery Clause ("SPPCRC"). As Mr. Kollen concedes on page 12, lines 16-17, some of the savings that may result from the SPP are unknown at this time. The company made it clear in its discovery responses that these savings will be captured in the SPPCRC moving forward if they materialize.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of A. Sloan Lewis was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

A. SLOAN LEWIS

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INTRODUCTION:

Q. Please state your name, address, occupation and employer.

A. My name is A. Sloan Lewis. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") in the Finance Department as Director, Regulatory Accounting.

Q. Are you the same A. Sloan Lewis who filed direct testimony in this proceeding?

A. Yes, I am.

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

A. The purpose of my rebuttal testimony is to address certain statements in the direct testimony and exhibits of Lane Kollen, who is testifying on behalf of Florida's Office of Public Council ("OPC") regarding the company's revenue requirements, rate impacts and 2020 Settlement Agreement.

Q. Are you sponsoring any exhibits in your rebuttal testimony in addition to the already filed exhibits in this proceeding?

A. Yes. I am sponsoring one additional exhibit entitled "2020 Settlement Agreement" which is identified as Exhibit No. ASL-2. The company filed a Motion to Approve the 2020 Agreement in this docket on April 27, 2020. Mr. Kollen discussed the contents of the 2020 Agreement in his testimony filed on May 26, 2020. The Commission subsequently approved the 2020 Agreement at a hearing held on June 9, 2020 in Docket No. 20200145-EI. I am including the 2020 Agreement as an exhibit to demonstrate how the Agreement resolves several of the issues Mr. Kollen mentioned in his direct testimony.

REBUTTAL TO DIRECT TESTIMONY OF LANE KOLLEN:

Q. Do you have any general comments regarding the overall direct testimony of Mr. Kollen?

A. Yes, overall Mr. Kollen is critical of the company's Storm Protection Plan (SPP"). His testimony also demonstrates that he has misinterpreted and misrepresented the company's calculation of the SPP revenue requirements and rate impacts and the company's 2020 Settlement Agreement. In addition, some of the issues raised by Mr. Kollen are resolved by the 2020 Agreement, and others are no longer accurate now that the Commission has approved the 2020 Agreement.

Q. Are any of the issues raised in Mr. Kollen's testimony resolved by the Commission's recent approval of the 2020 Agreement?

A. Yes. Mr. Kollen concedes that two of the main issues raised in his testimony would be resolved by approval of the 2020 Agreement. First, Mr. Kollen criticized the company for failing to exclude costs already captured in base rates from the estimated rate impact calculation for the plan. Footnotes 8 and 12 of his testimony acknowledge that this issue is resolved by the base rate reduction in the 2020 Agreement. Second, Mr. Kollen argued that the company did not adequately capture all of the cost savings that could result from implementation of the SPP. Footnotes 15 and 16 of his testimony acknowledge that this issue would be resolved by approval of the 2020 Agreement. Since the Commission approved the 2020 Agreement on June 9, 2020, these two issues have now been resolved.

Q. On Page 3, line 16 of his testimony, Mr. Kollen states, “The Company plans to spend $1,921 million on its proposed SPP projects over the ten-year life of the SPP Plan. The Company proposes revenue requirements of $972 million that it will likely seek to recover through the SPPCRC over that ten-year period.” Are these statements accurate?

A. No, as stated in the company’s SPP filing, the costs and associated revenue requirements within the plan were based upon a total of all storm protection and prior legacy storm hardening activities, which include items within base rates. The company will not be seeking cost recovery for some of these costs in the Storm Protection Cost Recovery Clause (“SPPCRC”).

Q. On Page 4, line 6 of his testimony, Mr. Kollen attempts to compare the estimated total spend and revenue requirements for the company's SPP to the company's present total net plant and revenues. Do you think his comparison is relevant?

A. No, I do not. These comparisons do not consider that the intent of the plan to advance the Legislature's policy goal to strengthen electric utility infrastructure to withstand extreme weather conditions. The company's plan is designed to achieve this goal by including those investments that will deliver the highest level of storm resiliency benefits at the lowest relative as explained in greater detail in the direct and rebuttal testimony of Tampa Electric's witnesses Regan Haines and Jason De Stigter.

Q. On Page 4, line 10 of his testimony, Mr. Kollen states that "TECO estimates that the rate increases for the residential class will be much greater than the rate increases for the commercial and industrial classes." Is this statement correct and if so, why is it so?

A. This criticism is misguided. First, Tampa Electric calculated the rate impacts by customer class using the cost allocation and rate design principles specified in the

2020 Agreement, to which the Office of Public Counsel is a party. Second, and more importantly, although the relative rate impact on residential customers will be greater than for many commercial and industrial customers, this reflects the fact that residential customers will receive benefits from more of the SPP projects within the company's proposed SPP than will many commercial and industrial customers.

Residential customers take service at the secondary service distribution level and thus benefit from projects that will improve reliability and resilience at the transmission, subtransmission, primary and secondary voltage levels. Many of the larger commercial and industrial customers take service at higher voltage levels of service (e.g., primary or subtransmission). Such customers will only benefit from improvements made to those higher level of service components of the electric system and using Commission approved cost of service allocators will thus not be allocated costs incurred at the lower voltage levels, and thus will pay a lower rate for SPP costs and investments. It is reasonable and appropriate that rate classes only pay for the portion of the SPP that benefits them.

Q. On Page 5, line 1 of his testimony, Mr. Kollen states that "The Company's proposed SPP total spend, increase in rate base, and increase in customers rates are significant." Do you agree with his assessment?

A. Yes, I agree. The company believes that any price increase is significant to customers, however, the Legislature found that it is in the state's interest to strengthen electric utility infrastructure to withstand extreme weather conditions and our plan was designed to advance this important public policy goal. As explained in greater detail in the direct and rebuttal testimony of Tampa Electric's witnesses Regan Haines and Jason De Stigter, the company's plan is designed to achieve this goal by including those investments that will deliver the highest level of storm resiliency benefits at the lowest relative cost.

Q. On Page 5, line 2 of his testimony, Mr. Kollen states that "these are incremental costs with incremental customer rate impacts." Is this statement correct?

A. No, as explained previously, the costs and revenue requirements provided in the company's SPP are inclusive of all storm protection and legacy storm hardening costs, not just incremental costs. Therefore, the rate impacts provided in the company's SPP are also inclusive of the total SPP costs.

Q. On Page 5, line 12 of his testimony, Mr. Kollen states that "the total multi-year customer rate impact can be considered only in the SPP proceedings." Do you agree with this statement?

A. Yes, that is why the company provided an estimate of the rate impact of the company's SPP for the first three years of the Plan, as required by Rule No. 25-6.030(3)(h) F.A.C. These rate impact estimates are located in Section 8 of Tampa Electric's SPP. Additionally, the company also provided estimates of the rate impact of the full ten-year Plan in response to OPC's Interrogatory No. 135, which was provided to OPC on May 5, 2020. Lastly, the company provided all working papers for the rate impact calculation in response to OPC's Request for Production of Documents No. 15, which was provided to OPC on April 28, 2020.

Q. On Page 5, line 17 of his testimony, Mr. Kollen states that "it is critical that the customer rate impact reflect only incremental cost of the SPP projects." Do you agree with this statement?

A. No, I do not agree with this statement. As stated previously, the company presented the full costs of the SPP projects in the Plan, pursuant to Rule No. 25-6.030(3)(h)

F.A.C. Therefore, the rate impacts presented in the plan are based on full costs, not what will be requested for recovery through the SPPCRC.

Q. With Commission approval of the 2020 Settlement Agreement how will the company ensure that no double recovery will occur?

A. The 2020 Settlement Agreement provides a base rate reduction at the same time as the SPPCRC goes into effect in January 2021, and other accounting and cost recovery provisions, to promote transparency and simplify the review of costs which the company will seek recovery through the SPPCRC and to avoid duplicative recovery of costs through the utility's existing base rates or any other cost recovery mechanism, as required by Rule No. 25-6.031 (6)(b) F.A.C. Even if the 2020 Settlement was not approved by the Commission, the company would have used the same methodology presented in the 2020 Settlement Agreement to ensure that only incremental costs will be charged to the SPPCRC and that double recovery would not occur.

Q. On Page 13, line 3 of his testimony, Mr. Kollen states “the Company provided an estimate of the incremental customer rate impact for the ten-year life of the SPP based on the sum of the return of and on the incremental capitalized cost and the incremental expenses." Do you agree with this statement?

A. I agree, in part. The company calculated the estimated customer rate impacts for the ten-year life of the SPP, with the expenses and return on capital presented in the SPP. The return on the capital costs are inherently incremental, as they include only capital expenditures for SPP projects initiated after the filing of the SPP. However, as stated previously, the expenses are based upon a total of all storm protection and prior legacy storm hardening activities, which include items previously recovered through base rates for which the company will not be seeking cost recovery through the SPPCRC.

Q. On Page 14, line 3 of his testimony, Mr. Kollen states that "The Company did not recognize the additional savings due to increases in cost-free accumulated deferred income taxes ("ADIT")." Is this statement accurate?

A. No, this statement is not accurate. The company considered ADIT in the same, consistent manner it does for every cost recovery clause it utilizes. The weighted average cost of capital ("WACC") used in the clause return on investment

("ROI") calculations includes ADIT as a zero-cost component of the capital structure. Inclusion of zero-cost ADIT results in a lower WACC. Since the SPP investments are multiplied against the WACC to determine a revenue requirement, inclusion of ADIT at zero cost results in savings to customers. Furthermore, as mentioned above, Mr. Kollen acknowledges that the 2020 Agreement resolves this issue in footnote 16 of his testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Transcript continues in sequence in Volume 3.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 13th day of August, 2020.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC