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JOSE R. OLIVA
Speaker of the House of Representatives

May 26, 2020

Adam J. Teitzman, Commission Clerk
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 20200069-EI– Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.

Dear Mr. Teitzman:

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

Should you have any questions please do not hesitate to contact Charles J. Rehwinkel at 850.488.9330

Sincerely,

/s/ *Charles J. Rehwinkel*

Charles J. Rehwinkel
Deputy Public Counsel

cc: All Parties of Record

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.	DOCKET NO.: 20200069-EI FILED: May 26, 2020

DIRECT TESTIMONY

OF

SCOTT NORWOOD

ON BEHALF OF THE OFFICE OF PUBLIC COUNSEL

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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

[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

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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. <u>COST EFFECTIVENESS OF PROPOSED SPP</u>

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?

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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.

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SUMMARY

Scott Norwood is an energy consultant with over 37 years of utility industry experience in the areas of regulatory consulting, resource planning and energy procurement. His clients include government agencies, publicly-owned utilities, public service commissions, municipalities and various electric consumer interests. Over the last 15 years Mr. Norwood has presented expert testimony on electric utility ratemaking, resource planning, and electric utility restructuring issues in over 200 regulatory proceedings in Arkansas, Georgia, Iowa, Illinois, Michigan, Missouri, New Jersey, Oklahoma, South Dakota, Texas, Virginia, Washington and Wisconsin.

Prior to founding Norwood Energy Consulting in January of 2004, Mr. Norwood was employed for 18 years by GDS Associates, Inc., a Marietta, Georgia based energy consulting firm. Mr. Norwood was a Principal of GDS and directed the firm's Deregulated Services Department which provided a range of consulting services including merchant plant due diligence studies, deregulated market price forecasts, power supply planning and procurement projects, electric restructuring policy analyses, and studies of power plant dispatch and production costs.

Before joining GDS, Mr. Norwood was employed by the Public Utility Commission of Texas as Manager of Power Plant Engineering from 1984 through 1986. He began his career in 1980 as Staff Electrical Engineer with the City of Austin's Electric Utility Department where he was in charge of electrical maintenance and design projects at three gas-fired power plants.

Mr. Norwood is a graduate of the college of electrical engineering of the University of Texas.

EXPERIENCE

The following summaries are representative of the range of projects conducted by Mr. Norwood over his 30-year consulting career.

Regulatory Consulting

Oklahoma Industrial Energy Consumers - Assisted client with technical and economic analysis of proposed EPA regulations and compliance plans involving control of air emissions and potential conversion of coal-to-gas conversion options.

Cities Served by Southwestern Electric Power Company – Analyzed and presented testimony regarding the prudence of a $1.7 billion coal-fired power plant and related settlement agreements with Sierra Club.

New York Public Service Commission - Conducted inter-company statistical benchmarking analysis of Consolidated Edison Company to provide the New York Public Service Commission with guidance in determining areas that should be reviewed in detailed management audit of the company.

Oklahoma Industrial Energy Consumers - Analyzed and presented testimony on affiliate energy trading transactions by AEP in ERCOT.

Virginia Attorney General – Analyzed and presented testimony regarding distribution tap line undergrounding program proposed by Dominion Virginia Power Company.

Cities Served by Southwestern Electric Power Company – Analyzed and presented testimony regarding the prudence of the utility's decision to retire the Welsh Unit 2 coal-fired generating unit in conjunction with a litigation settlement agreement with Sierra Club.

Georgia Public Service Commission - Presented testimony before the Georgia Public Service Commission in Docket 3840-U, providing recommendations on nuclear O&M levels for Hatch and Vogtle and recommending that a nuclear performance standard be implemented in the State of Georgia.

Oklahoma Industrial Energy Consumers - Analyzed and presented testimony addressing power production and coal plant dispatch issues in fuel prudence cases involving Oklahoma Gas and Electric Company.

Georgia Public Service Commission - Analyzed and provided recommendations regarding the reasonableness of nuclear O&M costs, fossil O&M costs and coal inventory levels reported in GPC's 1990 Surveillance Filing.

City of Houston - Analyzed and presented comments on various legislative proposals impacting retail electric and gas utility operations and rates in Texas.

New York Public Service Commission - Conducted inter-company statistical benchmarking analysis of Rochester Gas & Electric Company to provide the New York Public Service Commission with guidance in determining areas which should be reviewed in detailed management audit of the company.

Virginia Attorney General – Analyzed and presented testimony regarding an accelerated vegetation management program and rider proposed by Appalachian Power Company.

Oklahoma Attorney General – Analyzed and presented testimony regarding fuel and purchased power, depreciation and other expense items in Oklahoma Gas & Electric Company's 2001 rate case before the Oklahoma Corporation Commission.

City of Houston - Analyzed and presented testimony regarding fossil plant O&M expense levels in Houston Lighting & Power Company's rate case before the Public Utility Commission of Texas.

City of El Paso - Analyzed and presented testimony regarding regulatory and technical issues related to the Central & Southwest/El Paso Electric Company merger and rate proceedings before the PUCT, including analysis of merger synergy studies, fossil O&M and purchased power margins.

Residential Ratepayer Consortium - Analyzed Fermi 2 replacement power and operating performance issues in fuel reconciliation proceedings for Detroit Edison Company before the Michigan Public Service Commission.

Residential Ratepayer Consortium - Analyzed and prepared testimony addressing coal plant outage rate projections in the Consumer's Power Company fuel proceeding before the Michigan Public Service Commission.

City of El Paso - Analyzed and developed testimony regarding Palo Verde operations and maintenance expenses in El Paso Electric Company's 1991 rate case before the Public Utility Commission of Texas.

City of Houston - Analyzed and developed testimony regarding the operations and maintenance expenses and performance standards for the South Texas Nuclear Project, and operations and maintenance expenses for the Limestone and Parish coal-fired power plants in HL&P's 1991 rate case before the PUCT.

City of El Paso - Analyzed and developed testimony regarding Palo Verde operations and maintenance expenses in El Paso Electric Company's 1990 rate case before the Public Utility Commission of Texas. Recommendations were adopted.

Energy Planning and Procurement Services

Virginia Attorney General – Review and provide comments or testimony regarding annual integrated resource plan filings made by Dominion Virginia Power and Appalachian Power Company.

Dell Computer Corporation **–** Negotiated retail power supply agreement for Dell’s Round Rock, Texas facilities producing annual savings in excess of $2 million.

Texas Association of School Boards Electric Aggregation Program – Serve as TASB’s consultant in the development, marketing and administration of a retail electric aggregation program consisting of 2,500 Texas schools with a total load of over 300 MW. Program produced annual savings of more than $30 million in its first year.

Oklahoma Industrial Energy Consumers - Analyzed and drafted comments addressing integrated resource plan filings by Public Service Company of Oklahoma and Oklahoma Gas and Electric Company.

S.C. Johnson - Analyzed and presented testimony addressing Wisconsin Electric Power Company's $4.1 billion CPCN application to construct three coal-fired generating units in southeast Wisconsin.

Oklahoma Industrial Energy Consumers - Analyzed wind energy project ownership proposals by Oklahoma Gas and Electric Company and presented testimony addressing project economics and operational impacts.

City of Chicago, Illinois Attorney General, Illinois Citizens' Utility Board - Analyzed Commonwealth Edison's proposed divestiture of the Kincaid and State Line power plants to SEI and Dominion Resources.

Georgia Public Service Commission - Analyzed and presented testimony on Georgia Power Company's integrated resource plan in a certification proceeding for an eight unit, 640 MW combustion turbine facility.

South Dakota Public Service Commission - Evaluated integrated resource plan and power plant certification filing of Black Hills Power & Light Company.

Shell Leasing Co. - Evaluated market value of 540 MW western coal-fired power plant.

Community Energy Electric Aggregation Program – Served as Community Energy's consultant in the development, marketing and start-up of a retail electric aggregation program consisting of major charitable organizations and their donors in Texas.

Austin Energy – Conducted competitive solicitation for peaking capacity. Developed request for proposal, administered solicitation and evaluated bids.

Austin Energy - Provided technical assistance in the evaluation of the economic viability of the City of Austin's ownership interest in the South Texas Project.

Austin Energy - Assisted with regional production cost modeling analysis to assess production cost savings associated with various public power merger and power pool alternatives.

Sam Rayburn G&T Electric Cooperative - Conducted competitive solicitation for peaking capacity. Developed request for proposal, administered solicitation and evaluated bids.

Rio Grande Electric Cooperative, Inc. - Directed preparation of power supply solicitation and conducted economic and technical analysis of offers.

Virginia Attorney General – Review and provide comments or testimony regarding annual demand-side management program programs and rider proposals made by Dominion Virginia Power and Appalachian Power Company.

Austin Energy – Conducted modeling to assess potential costs and benefits of a municipal power pool in Texas.

Electric Restructuring Analyses

Electric Power Research Institute - Evaluated regional resource planning and power market dispatch impacts on rail transportation and coal supply procurement strategies and costs.

Arkansas House of Representatives – Critiqued proposed electric restructuring legislation and identified suggested amendments to provide increased protections for small consumers.

Virginia Legislative Committee on Electric Utility Restructuring – Presented report on status of stranded cost recovery for Virginia's electric utilities.

Georgia Public Service Commission – Developed models and a modeling process for preparing initial estimates of stranded costs for major electric utilities serving the state of Georgia.

City of Houston – Evaluated and recommended adjustments to Reliant Energy's stranded cost proposal before the Public Utility Commission of Texas.

Oklahoma Attorney General – Evaluated and advised the Attorney General on technical, economic and regulatory policy issues arising from various electric restructuring proposals considered by the Oklahoma Electric Restructuring Advisory Committee.

State of Hawaii Department of Business, Economics and Tourism – Evaluated electric restructuring proposals and developed models to assess the potential savings from deregulation of the Oahu power market.

Virginia Attorney General - Served as the Attorney General's consultant and expert witness in the evaluation of electric restructuring legislation, restructuring rulemakings and utility proposals addressing retail pilot programs, stranded costs, rate unbundling, functional separation plans, and competitive metering.

Western Public Power Producers, Inc. - Evaluated operational, cost and regional competitive impacts of the proposed merger of Southwestern Public Service Company and Public Service Company of Colorado.

Iowa Department of Justice, Consumer Advocate Division - Analyzed stranded investment and fuel recover issues resulting from a market-based pricing proposal submitted by MidAmerican Energy Company.

Cullen Weston Pines & Bach/Citizens' Utility Board - Evaluated estimated costs and benefits of the proposed merger of Wisconsin Energy Corporation and Northern States Power Company (Primergy).

City of El Paso - Evaluated merger synergies and plant valuation issues related to the proposed acquisition and merger of El Paso Electric Company and Central & Southwest Company.

Rio Grande Electric Cooperative, Inc. - Analyzed stranded generation investment issues for Central Power & Light Company.

Power Plant Management

City of Austin Electric Utility Department - Analyzed the 1994 Operating Budget for the South Texas Nuclear Project (STNP) and assisted in the development of long-term performance and expense projections and divestiture strategies for Austin's ownership interest in the STNP.

City of Austin Electric Utility Department - Analyzed and provided recommendations regarding the 1991 capital and O&M budgets for the South Texas Nuclear Project.

Sam Rayburn G&T Electric Cooperative - Developed and conducted operational monitoring program relative to minority owner's interest in Nelson 6 Coal Station operated by Gulf States Utilities.

KAMO Electric Cooperative, City of Brownsville and Oklahoma Municipal Power Agency - Directed an operational audit of the Oklaunion coal-fired power plant.

Sam Rayburn G&T Electric Cooperative - Conducted a management/technical assessment of the Big Cajun II coal-fired power plant in conjunction with ownership feasibility studies for the project.

Kamo Electric Power Cooperative - Developed and conducted operational monitoring program for client's minority interest in GRDA Unit 2 Coal Fired Station.

Northeast Texas Electric Cooperative - Developed and conducted operational monitoring program concerning NTEC's interest in Pirkey Coal Station operated by Southwestern Electric Power Company and Dolet Hills Station operated by Central Louisiana Electric Company.

Corn Belt Electric Cooperative/Central Iowa Power Cooperative - Perform operational monitoring and budget analysis on behalf of co-owners of the Duane Arnold Energy Center.

PRESENTATIONS

Quantifying Impacts of Electric Restructuring: Dynamic Analysis of Power Markets, 1997 NARUC Winter Meetings, Committee on Finance and Technology.

Quantifying Costs and Benefits of Electric Utility Deregulation: Dynamic Analysis of Regional Power Markets, International Association for Energy Economics, 1996 Annual North American Conference.

Railroad Rates and Utility Dispatch Case Studies, 1996 EPRI Fuel Supply Seminar.

	Lateral Hardening UG: replaces most outage prone lines and places them underground eliminating opportunity for breakage **Lateral Hardening OH:** strengthened structures, increased line spacing, decreased structure spacing and increased conductor strength reduces likelihood of breakage, replaces fuse devices with automatic reclosing devices allowing for temporary faults to clear **Self-Optimizing Grid:** enables the system to reroute power around damage, restoring service to some customers automatically
Lightning	**Feeder Hardening:** increased BIL **Lateral Hardening UG:** replaces most outage prone lines and places them underground reducing opportunity for lightning strikes **Lateral Hardening OH:** increased BIL, replaces fuse devices with automatic reclosing devices allowing for temporary faults to clear **Self-Optimizing Grid:** enables the system to reroute power around damage, restoring service to some customers automatically
Other Weather	**Feeder Hardening:** strengthened structures, increased line spacing, decreased structure spacing reduces likelihood of breakage **Lateral Hardening UG:** replaces most outage prone lines and places them underground eliminating opportunity for breakage **Lateral Hardening OH:** strengthened structures, increased line spacing, decreased structure spacing and increased conductor strength reduces likelihood of breakage, replaces fuse devices with automatic reclosing devices allowing for temporary faults to clear **Self-Optimizing Grid:** enables the system to reroute power around damage, restoring service to some customers automatically
Vehicle/Public Damage	**Self-Optimizing Grid:** enables the system to reroute power around damage, restoring service to some customers automatically

96. Please provide the definition used for "extreme weather conditions" and "extreme weather events" as applied by the Company in identifying the outage events targeted by the SPP.

Response:
In the application of outage events targeted by the SPP, DEF used "extreme weather conditions" and "extreme weather events" in three ways within the Guidehouse analysis: future events, past events (for failure), and past events (for calibration). The definitions are consistent, with nuances in their application, which are outlined below.

Future events were defined as probabilistic weather scenarios and were included in the analysis to estimate the frequency of Tropical Storms and Category 1 through 5 hurricanes, as defined by the Saffir Simpson scale. Any weather event less than Tropical Storm wind speed, or 4-foot flooding, was classified as Non-MED. This forward-looking definition was used to categorize and estimate annual CMI reduction and restoration cost reductions by Non-MED and MED.

Past events (for failure) were analyzed to characterize the likelihood of equipment failure. Equipment failures cause outage events in the analysis and can be avoided or reduced through asset hardening as described in Appendix 1 of JWO-Exhibit 4. Using the same Saffir Simpson Scale, the conditional likelihood of failure given a specific weather condition was derived by referencing local historical weather events during historical

observed outages.
Past events (for calibration) were used to calibrate the Guidehouse analysis with DEF's actual CMI. DEF annual reliability reports were used, and these reports grouped events into MED vs. Non-MED.

97. Please provide the annual O&M and capital expenditures for storm restoration activities due to outages caused by extreme weather conditions and/or events for each of the last ten calendar years and explain how such amounts were recovered through the Company's retail rates during this period.

Response:
Subject to and without waiving DEF's objection contemporaneously filed with this request, please see the table below providing the 2016 – 2019 major storm restoration costs as requested above. Actuals prior to 2015 are not reasonably accessible due to a financial system conversion.

2018 and 2019 represent estimates as these costs have not been finalized. There were no major storms in 2015. The Company is currently going through the Storm Cost recovery process for these years. The costs below reflect total Company costs for these major storms and do not reflect any adjustments for non-incremental costs nor Jurisdictional factors.

Generally, recent incremental named storm costs are being recovered through base rates using the tax savings from the Tax Cuts and Jobs Act or the storm charge in the case of costs associated with Hurricane Dorian and Tropical Storm Nestor.

Values in Millions

	2016 Actuals	2017 Actuals	2018 Estimated Costs	2019 Estimated Costs
Storm Costs	67.1	434.1	210.6	165.1
Storm Capital Costs	3.1	26.4	106.4	0.2
Total	**70.2**	**460.4**	**317.0**	**165.3**

98. Please provide the Company's annual SAIDI and SAIFI attributable to extreme weather conditions and/or events for each year since 2000.

Response:
Subject to and without waiving DEF's objection contemporaneously filed with this request, please see the document bearing bates number 20200069-DEF-001221, for SAIDI and SAIFI attributable to extreme weather conditions and/or events from 2006 to 2019. Data prior to 2006 is not available.

108. Please discuss the extent to which the SPP is expected to reduce the number of momentary or short duration outages on the Company's system.

Response:
SPP programs will reduce momentary interruptions significantly. The best example is the Lateral Hardening Program which includes undergrounding of laterals in heavily vegetated areas. Limbs and animals contacting these lines are the cause of large numbers of momentary interruptions. This exposure is greatly reduced through undergrounding.

109. Please provide the Company's O&M and capital expenditures (separately) for grid hardening activities for each of the last five calendar years and describe the primary scope of such activities.

Response:
Subject to and without waiving DEF's objection contemporaneously filed with this request, as outlined and described in DEF's 2019-2021 Storm Hardening Plan and SPP JWO Exhibit 1, Duke Energy's major existing programs for grid hardening in Florida are:

- Base Storm Hardening
- Pole Inspections
- Pole Replacements
- Targeted Undergrounding
- Self-Optimizing Grid
- Transformer Retrofit
- Deteriorated Conductor
- Live-front Switchgear Replacement

Transmission
- Maintenance Change outs
- Wood Pole Inspection Program
- Wood to Non-Wood Upgrade
- Overhead Ground Wire (OHGW)
- Structure Inspections
- Substation Hardening with sub programs:
  - Breaker upgrades
  - Electronic relay

Please see the document bearing bates number 20200069-DEF-001224, for O&M and capital expenditures for the last 5 calendar years as requested.

110. Please provide the Company's O&M and capital expenditures (separately) for vegetation management activities for each of the last five calendar years and describe the primary scope and cycle of such activities.

Response:
Subject to and without waiving DEF's objection contemporaneously filed with this request,

	2015	2016	2017	2018	2019
Total O&M	$ 42,661,466	$ 37,943,497	$ 35,886,368	$ 42,369,906	$ 57,863,684
Total Capital	$ 1,431,911	$ 2,133,273	$ 2,804,987	$ 4,414,825	$ 7,389,189
Grand Total	**$ 44,093,377**	**$ 40,076,770**	**$ 38,691,355**	**$ 46,784,731**	**$ 65,252,873**
	Dollars include both Transmission and Distribution Vegetation Management				

Primary Scope and Cycle:
The Duke Energy Florida Integrated Vegetation Management (IVM) Program ensures the safe and reliable operation of the electric system by minimizing vegetation-related interruptions and ensuring adequate conductor-to-vegetation clearances, while maintaining compliance with regulatory, environmental, and safety requirements or standards. Duke Energy Florida Distribution IVM program focuses on trimming feeders and laterals on an average of 3- and 5-year cycles respectively. Duke Energy Florida Transmission IVM program scheduled and prioritized planned work through a manual process using the date of previous work activities as well as threats and conditions identified through patrols, inspections and assessments.

111. Please identify the specific circuits that the Company has targeted for grid hardening or other grid enhancements under the SPP, along with the SAIDI and SAIFI statistics for each such circuit with and without extreme weather conditions and/or events for each of the last five calendar years.

Response:

SAIDI and SAIFI for the circuits listed in Exhibit 1 for adjusted and unadjusted data, as measured by the Florida Public Service Commission, see the document bearing bates numbers 20200069-DEF-001225 through 20200069-DEF-001252. Due to the dynamic nature of the distribution grid, DEF does not have a report available that tracks the customers on individual circuits for previous years, so SAIDI and SAIFI are based on current customer counts.

Exhibit 2 circuits have not yet been selected.

112. Please provide the Company's total annual transmission investments for each of the last ten calendar years, along with the portion of those investments that were made to serve customer growth, the portion of investments to maintain or improve reliability, and the portion of investments for other factors (i.e., not primarily related to customer growth or reliability).

Response:

In re: Review of 2020-2029 Storm Protection
Plan Pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC
Docket No. 20200069-EI
Interrogatories
ROG DR 3-109

Program	Account Class	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals
Targeted Undergrounding	Capital Expenditures	-	-	243,674	3,717,859	17,740,859
	O&M	-	28,851	6,554	56,950	203,245
Self-Optimizing Grid	Capital Expenditures	1,015,965	13,250,275	15,281,177	28,442,268	45,752,826
	O&M	92,144	1,053,918	727,053	755,201	1,058,334
Transformer Retrofit	Capital Expenditures	19,620	41,871	89,728	3,773,823	20,135,130
	O&M	-	-	-	63,040	790,218
Deteriorated Conductor	Capital Expenditures	6,576,787	3,397,991	1,297,374	5,951,925	18,087,267
	O&M	328,271	122,176	39,542	38,215	590,071
Live-Front Switchgear Replacement	Capital Expenditures	-	-	-	-	2,830,036
	O&M					4,970
Base Storm Hardening	Capital Expenditures	11,455,171	6,569,317	8,043,722	13,598,475	12,921,049
	O&M	175,905	273,690	102,789	141,538	216,796
Distribution Pole Replacements	Capital Expenditures	46,737,371	29,818,284	24,446,746	26,170,092	32,656,508
Distribution Pole Inspections & Project O&M for Pole Replacements	O&M	3,789,999	4,925,496	5,727,605	5,285,474	5,248,813
Wood to Non-Wood Upgrade	Capital Expenditures	66,155,497	21,980,714	14,676,821	32,047,884	34,429,685
Overhead Ground Wire (OHGW)	Capital Expenditures	1,192,058	737,099	1,080,416	6,419,488	5,662,644
Transmission Pole Inspections & Project O&M for Structure Hardening	O&M	1,239,613	1,450,389	580,082	1,591,931	2,320,597
Substation Hardening - Breaker Upgrades / Electronic Relays	Capital Expenditures	4,764,009	12,580,017	21,658,113	24,515,069	21,710,669
Substation Hardening O&M	O&M	2,934	238,822	121,525	1,067	13,264
	Subtotal Capital Expenditures	**137,916,478**	**88,375,566**	**86,817,771**	**144,636,884**	**211,926,673**
	Subtotal O&M	**5,628,866**	**8,093,342**	**7,305,150**	**7,933,417**	**10,446,307**

observed outages.
Past events (for calibration) were used to calibrate the Guidehouse analysis with DEF's actual CMI. DEF annual reliability reports were used, and these reports grouped events into MED vs. Non-MED.

97. Please provide the annual O&M and capital expenditures for storm restoration activities due to outages caused by extreme weather conditions and/or events for each of the last ten calendar years and explain how such amounts were recovered through the Company's retail rates during this period.

Response:
Subject to and without waiving DEF's objection contemporaneously filed with this request, please see the table below providing the 2016 – 2019 major storm restoration costs as requested above. Actuals prior to 2015 are not reasonably accessible due to a financial system conversion.

2018 and 2019 represent estimates as these costs have not been finalized. There were no major storms in 2015. The Company is currently going through the Storm Cost recovery process for these years. The costs below reflect total Company costs for these major storms and do not reflect any adjustments for non-incremental costs nor Jurisdictional factors.

Generally, recent incremental named storm costs are being recovered through base rates using the tax savings from the Tax Cuts and Jobs Act or the storm charge in the case of costs associated with Hurricane Dorian and Tropical Storm Nestor.

Values in Millions

	2016 Actuals	2017 Actuals	2018 Estimated Costs	2019 Estimated Costs
Storm Costs	67.1	434.1	210.6	165.1
Storm Capital Costs	3.1	26.4	106.4	0.2
Total	**70.2**	**460.4**	**317.0**	**165.3**

98. Please provide the Company's annual SAIDI and SAIFI attributable to extreme weather conditions and/or events for each year since 2000.

Response:
Subject to and without waiving DEF's objection contemporaneously filed with this request, please see the document bearing bates number 20200069-DEF-001221, for SAIDI and SAIFI attributable to extreme weather conditions and/or events from 2006 to 2019. Data prior to 2006 is not available.

Forecasted vs Actual SAIDI Impacts of EWEs and Hurricane Irma

	OPC ROG 3--98 Extreme Events	per OPC Rog 6-219 Actual CMI	per OPC Rog 6-219 Fcst P50 CMI Avg	per OPC Rog 6-219 Fcst CMI Above Avg	per OPC Rog 6-219 Fcst CMI High	per OPC Rog 6-219 Actual CMI
2006	7	24,370,391				24,370,391
2007	6	30,267,833				30,267,833
2008	9	113,305,591				113,305,591
2009	9	10,199,262				10,199,262
2010	3	3,938,063				3,938,063
2011	3	105,277,013				105,277,013
2012	5	77,595,047				77,595,047
2013	4	4,073,213				4,073,213
2014	1	610,383				610,383
2015	1	260,028				260,028
2016	5	458,371,844				458,371,844
2017	3	4,372,367,728				
2018	4	188,928,874				188,928,874
2019	2	5,745,874				5,745,874
Total:	62	5,395,311,144				1,022,943,416
Average:	**4.4**	385,379,367	1,119,640,732	1,231,604,805	1,399,550,915	78,687,955
SAIDI		**214**	**622**			**44**
Forecast Times Average:			**2.9**	3.2	3.6	
			14.2			
% of CMI Due to Irma		**81.0%**				

The following numbers follow the FPSC methodology for the "adjusted" SAIDI and SAIFI for the years requested plus the transmission non severe weather which is typically excluded from the "adjusted" numbers.

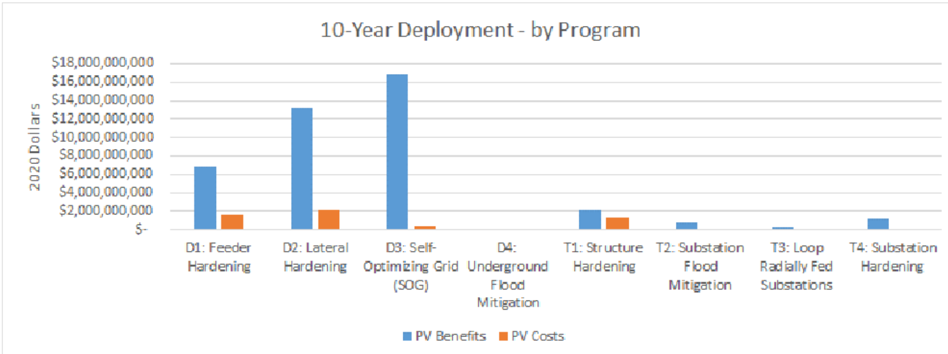
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SAIDI	102.2	97.8	79.7	95.4	93.5	87.9	93.5	92.9	110.3	98.8
SAIFI	1.41	1.24	1.09	1.25	1.28	1.15	1.16	1.15	1.21	1.14

48. Please explain any factors unique to the Company's Florida service area that contribute to higher SAIDI or SAIFI performance in the Florida jurisdiction when compared to SAIDI or SAIFI performance by utilities in other regions.

Response:
Some factors that contribute to higher SAIDI and SAIFI compared to other regions are DEF's service area is more susceptible to extreme weather events (hurricanes and tropical storms) and non-extreme weather events (thunder storms and high winds) due to having more coastline than any other continental state and having the highest lightning volume of all other regions.

49. Please provide your cost/benefit analyses supporting each major component of the Company's proposed Storm Protection Plan ("SPP").

Response:
The cost/benefit analysis for each main program for the Company's proposed Storm Protection Plan is shown below. It reflects the "Probability of Damage" and "Consequence of Damage" prioritization methodology directly from the Guidehouse model over the 10 year-period of the proposed SPP. The cost/benefit analysis results shown do not include the additional and final level of asset prioritization that will occur by subject matter experts within the Distribution and Transmission business units. As stated in SPP Exhibit JWO-2, that portion of prioritization will use the model outputs to "determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability".



50. Please provide your cost/benefit analysis along with any other expected non-monetary benefits supporting your proposed SPP for Florida.

Response:
Please see DEF's response OPC's interrogatory number 49. Other expected non-monetary benefits supporting DEF's proposed SPP for Florida were not included in the cost/benefit analysis.

51. Please provide the estimated O&M and capital expenditures for the Company's SPP by FERC account (if available) for the next five calendar years (or as many years as is available).

Response:
DEF does not have the requested information in the format requested (i.e., by FERC account).

52. Please identify the expected improvement in the Company's SAIDI and SAIFI performance in Florida with and without major storms over the next ten years due to implementation of the SPP, along with the basis and assumptions used for deriving such forecasts. Please also identify the principal source documents containing the information requested in this Interrogatory.

Response:
Analysis on the expected improvement in DEF's SAIDI and SAIFI performance in Florida with and without major storms over the next ten years was not completed, as that specific type of analysis was not required in the SPP rules. However, the expected Customer Minutes of Interruption (CMI) savings were analyzed and calculated. Please refer to SPP Exhibit No. ___(JWO-2) for CMI reductions per program in DEF's SPP.

Response:

The reliability-related complaints DEF has received each of the last 10 years are reported in DEF's annual reliability reports, available from the Commission's website. The totals are summarized below.

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
204	221	204	179	192	187	173	420	271	251

21. Please provide the documents containing your documentation of the total number of complaints due to transmission service reliability problems in the Company's Florida service area for each of the last ten years.

Response:
Please see DEF's response to OPC's Request for Production of Documents number 20. Transmission and Distribution complaints are not separated internally.

22. Please provide copies of any tariffs or terms and conditions available to customers in the Company's Florida service area that provide for customers to obtain higher than standard transmission or distribution service reliability, and identify the number of customers in each rate class who requested and were served under such tariffs or terms for each of the last five calendar years.

Response:
Please see that attached documents bearing bates number 2020069-DEF-000279 through 20200069-000376. DEF has the option for premium distribution service (PDS) offered on all non-residential tariffs per section 2.05 of the General Rules and Regulations Governing Electric Service. The applicable sections of the General Rules and Regulations and the specific tariffs have been highlighted in the provided tariff copies.

All DEF customers that were served using PDS offered in the tariffs in the last five calendar years were served on the General Service Demand (GSD) rate class. See below for the annual count since 2015.

2015: 26 PDS customers; All GSD
2016: 26 PDS customers; All GSD
2017: 27 PDS customers; All GSD
2018: 29 PDS customers; All GSD
2019: 30 PDS customers; All GSD

23. Please provide the documents containing the cost/benefit analyses supporting each major component of your proposed Storm Protection Plan ("SPP") as required by Rule 25-6.030(3) and as requested in Citizens Second Set of Interrogatories, No. 49, including all

calculations and underlying assumptions supporting each analyses. Please also produce any document identified in such response.

Response:
Please see Exhibit Nos.___(JWO-1),___(JWO-2), and___(JWO-4), as well as the attached documents bearing bates numbers 20200069-DEF-000401 through 20200069-DEF-000404. The documents are confidential. Due to the size of the confidential document bearing bates number 2020069-DEF-000401, it is being provided in Excel Format only. Redacted slip-sheets have been attached hereto and unredacted copies have been filed with the Florida Public Service Commission ("Commission") along with DEF's Notice of Intent to Request Confidential Classification dated April 27, 2020. The referenced exhibits provide the information required by the rule.

24. Please provide the documents containing each cost/benefit analyses and all other information presented to your management supporting the decisions to implement the SPP and major components of the SPP.

Response:
Please see the attached documents bearing bates numbers 20200069-DEF-000377 through 20200069-DEF-000397. The documents are confidential. Redacted versions have been attached hereto and unredacted copies have been filed with the Florida Public Service Commission ("Commission") along with DEF's Notice of Intent to Request Confidential Classification dated April 27, 2020.

25. Please provide the documents containing the cost/benefit analysis, along with any other expected non-monetary benefits, supporting your proposed SPP for Florida as required by Rule 25-6.030(3) or as requested in Citizens Second Set of Interrogatories, No. 50 including all calculations and underlying assumptions supporting each analyses. Please also produce any document identified in such response.

Response:
Please see DEF's response to OPC's Request for Production number 23.

26. Please provide the documents containing all utility industry surveys or benchmarking analyses prepared within the last four calendar years comparing the Company's SAIDI or SAIFI performance (that both include and exclude major storms) to the SAIDI or SAIFI performance of other utilities.

Response:
Please reference the Annual Electric Industry Power Report, EIA-861 for SAIDI and SAIFI performance of Duke Energy Florida and other utilities. This information can be found at https://www.eia.gov/electricity/data/eia861/. Duke Energy Florida also participates in benchmarking with the Southeastern Electric Exchange.

27. Please produce the documents identified in Citizens Interrogatory No. 52.

250. Reference page 29 of Exhibit JWO-4 of Company witness Oliver's direct testimony, please provide the average outage restoration cost per year for each listed category of event types that are forecasted to impact the DEF system over the study period used for your cost/benefit analyses of each SPP Project assuming DEF's proposed SPP is deployed.

Response:
Subject to and without waiving the objections filed on May 11, 2020, please see the attached file bearing bates numbers 20200069-DEF-003336 through 20200069-DEF-003337.

251. Identify each alternative future scenario that was evaluated to determine the estimated benefits of deploying each of DEF's proposed SPP Programs, and provide the estimated costs, CMI reduction and outage restoration cost benefits associated with each such alternative scenario.

Response:
Subject to and without waiving the objections filed on May 11, 2020, please see the attached file bearing bates number 20200069-DEF-003338.

252. Please provide the following information regarding the performance of DEF's system during major weather events related to assets that would be addressed under each proposed SPP Project in an electronic machine-readable format:

a. Annual CMI each year due to major weather events since 2000;
b. Annual SAIDI impact each year due to major weather events since 2000;
c. Annual restoration cost due to major weather events since 2000
d. Forecasted average CMI per year over the study period used for cost/benefit analyses of each SPP Project;
e. Forecasted average annual SAIDI impact over the study period used for cost/benefit analyses of each SPP Project; and
f. Forecasted average annual restoration cost due to major weather events over the study period used for cost/benefit analyses of each SPP Project.

Response:
Subject to and without waiving the objections filed on May 11, 2020, Distribution data is available back to 2008 and Transmission data is available back to 2006.
For parts a and b, see bearing bates numbers 20200069-DEF-003330 through 20200069-DEF-003332 (copied details below).

The Distribution Storm Protection Plan projects the assets that will be addressed are as follows:

- Feeder Hardening
    - Breaker

Program	(a) CMI Benefit	(b) Restoration Cost Benefit	(c) Life cycle Gross Benefit	(d) Life cycle Net Benefit	(e1) Life cycle B/C w/ ICE	(e2) Life cycle B/C w/o ICE	Life cycle Costs	Life cycle Benefits w/o ICE
D1: Feeder Hardening	$ 6,452,860,759	$ 6,860,309	$ 6,830,030,890	$ 5,292,895,906	4.44	0.25	$ 1,537,134,984	$ 377,170,131
D2: Lateral Hardening	$ 11,981,317,309	$ 75,107,488	$ 13,189,744,721	$ 11,378,902,736	7.79	0.67	$ 1,810,841,985	$ 1,707,926,917
D3: Self-Optimizing Grid (SOG)	$ 16,803,556,110	$ -	$ 16,803,565,110	$ 16,547,936,805	65.73	-	$ 255,628,305	$ -
D4: Underground Flood Mitigation	$ 29,221,879	$ 904,625	$ 45,177,747	$ 34,372,400	4.18	1.48	$ 10,805,348	$ 15,955,869
T1: Structure Hardening	$ 1,439,556,330	$ 16,086,454	$ 2,231,398,620	$ 932,460,472	1.72	0.61	$ 1,298,938,148	$ 791,842,289
T2: Substation Flood Mitigation	$ 755,057,704	$ 270,127	$ 762,511,417	$ 732,871,417	25.73	0.23	$ 29,640,000	$ 6,853,053
T3: Loop Radially Fed Substations	$ 166,759,807	$	$ 167,430,977	$ 109,416,977	2.89	0.01	$ 58,014,000	$ 671,170
T4: Substation Hardening	$ 1,126,917,599	$ 71,318	$ 1,133,948,395	$ 1,030,570,795	10.97	0.07	$ 103,377,600	$ 7,030,796

Notes:
Based on projects deployed over the 10-year study period
All values based on the Average Storm Frequency weather scenario
All values are present values (2020 dollars) over the assumed useful lifetime (30 years for distribution, 40 years for transmission)
(b) restoration cost benefits include both MED and non-MED

Subject to and without waiving DEF's objection contemporaneously filed with this request, please see the document bearing bates number 20200069-DEF-001253, for the Company's total annual transmission investments by Category for each of the last 5 calendar years. Actuals prior to 2015 are not reasonably accessible due to a financial system conversion.

113. Please provide the total number of the Company's retail customers served at transmission voltages for each of the last five calendar years.

Response:
DEF had the following number of retail customers served at transmission voltages for each of the specified years:

2015: 20
2016: 20
2017: 19
2018: 17
2019: 17

114. Please provide the total number of the Company's customers served at distribution voltages for each of the last five calendar years.

Response:
Please see DEF's Annual Reliability Reports for the previously filed customer counts for the years requested.

115. Please identify past Company investments that have been approved based on results of cost/benefit analyses developed using the DOE ICE software and identify the Docket No. and Order in which these approvals were granted.

Response:
There are no approved DEF investments that meet these criteria.

116. Please identify past Company electric system investments that have been approved based on estimated customer savings, which are not directly reflected in electric bill savings, and identify the Docket No. and Order in which these approvals were granted.

Response:
DEF cannot speculate regarding what considerations individual Commissioners or the Commission as a whole took into account when approving any of DEF's previous investments; the best evidence of the Commission's reasoning for any decision is memorialized in the Commission's Orders and comments made on the record. That said, the Company is not aware of any past investments approved specifically based on estimated customer savings, which are not directly reflected in electric bill savings, but the Company

has also not undertaken an exhaustive review of previous Commission Orders or comments, which the Company notes are public records and available to OPC.

Moreover, DEF makes electric system investments for a variety of reasons and most are made without seeking direct approval based on customer savings. Many investments are required for system reliability where if one were to only consider customer bill savings, investing in reliability may not be cost-justified. The Company notes that improvement in accepted reliability indices such as SAIDI, SAIFI, and MAIFI (both MED and non-MED) benefit customers; these measures serve as a proxy for customer value.

Finally, the legislature has determined that "It is in the state's interest to strengthen electric utility infrastructure to withstand extreme weather conditions . . . [because] Protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers . . . [and] It is in the state's interest for each utility to mitigate restoration costs and outage times to utility customers." *See* § 366.96(1)(c), (d), & (e), Fla. Stat. Reduced restoration costs are reflected on customer's bills as those prudently incurred costs are borne by customers, but "reduced outage times" are not; therefore, the legislature has made clear it sees value in this estimated benefit not directly reflected in electric bill savings.

117. Please identify past Company investments that have been approved based on estimated customer avoidance of lost revenues caused by electric service outages, which are not directly reflected in electric bill savings, and identify the Docket No. and Order in which these approvals were granted.

Response:
Please see DEF's response to OPC ROG 3-116.

118. Please identify past Company projects and/or programs that have been approved based on estimated customer desire for improved service reliability, which is not directly reflected in electric bill savings, and identify the Docket No. and Order in which these approvals were granted.

Response:
Please see DEF's response to OPC ROG 3-116.

119. Please provide the results from any and all surveys conducted by and on behalf of the Company to determine the optimal level of service reliability (e.g., SAIDI and SAIFI) desired by customers who take service at distribution voltages.

Response:
Duke Energy's Customer Experience Monitor (CX Monitor) is a randomized, census-based survey, measuring ongoing perceptions of the customer experience annually via an email invite with an embedded online survey link to ALL Duke Energy residential and small medium business ("SMB") customers for whom we have a valid email address.

DEF's SPP CBA Costs and Benefits

SPP Program	Life Cost	Non-Electric (ICE) Customer Benefit
Feeder Hardening	$1,537.1	$6,452.9
Lateral Hardening	$1,810.3	$11,981.3
Self Optimizing Grid	$255.6	$16,803.6
Underground Flood Mitigation	$10.8	$29.2
Distr Vegetation Management	$497.0	
Trans Structure Hardening	$1,298.9	$1,439.6
Substation Flood Mitigation	$29.6	$755.7
Loop Radially Fed Substations	$58.0	$166.8
Substation Hardening	$103.4	$1,126.9
Trans Vegetation Management	$198.0	-
SPP Totals	$5,798.7	**$38,756.0**
Total Distribution Programs	$4,110.8	$35,267.0
Total Transmission Programs	$1,687.9	$3,489.0

Source: DEF response to OPC ROG 8-251

SPP Program Benefit/Cost Ratios Excluding Non-Electric Benefits

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

Sources: OPC ROG 8-253 & 8-251

Subject to and without waiving the objections filed on May 11, 2020, please see the document provided in DEF's response to OPC's ROG 8-237 for total annual restoration costs by storm category from 2012 through 2019. Additionally, as filed in Docket No. 041272-EI, in 2004, total storm damage was $384M. In 2005, total storm damage was $7.6M. Costs beyond these timeframes are not available.

248. Reference page 29 of Exhibit JWO-4 of Company witness Oliver's direct testimony, please provide the average CMI per year and average annual SAIDI contribution for each listed category of event types that are forecasted to impact the DEF system over the study period used for cost/benefit analyses of each SPP Project assuming DEF's proposed SPP is deployed.

Response:
Subject to and without waiving the objections filed on May 11, 2020, please see the attached documents bearing bates numbers 20200069-DEF-003334 through 20200069-DEF-003335. Note this data is not available by project but is available by program. Thus, the Company has provided the program level data.

249. Reference page 29 of Exhibit JWO-4 of Company witness Oliver's direct testimony, please provide the average number of events per year for each listed category of event types that are forecasted to impact the DEF system over the study period used for your cost/benefit analyses of each SPP Project assuming DEF's proposed SPP is deployed.

Response:
Subject to and without waiving the objections filed on May 11, 2020, storm frequency was evaluated for the entire available Atlantic tropical storm data history (~200 years). Average tropical storm duration in Duke Energy Florida territory is ~23 hours. This is calculated from the NOAA HURDAT database of Atlantic tropic cyclones. Page B-2 in Appendix 2 provides the average probability of any given ~23-hour period falling into each storm category, over the territory, as a summary of the local probabilities derived from the HAZUS model by Guidehouse in the SPP analysis. These probabilities are constant over the forecast horizon for each scenario for each location. Converting these probabilities to frequencies (events/year), and averaging over all DEF locations gives the following approximate frequencies (events/year):

Tropical Storm	**Category 1**	**Category 2**	**Category 3**	**Category 4**	**Category 5**
1.2876	0.0935	0.0187	0.0063	0.0016	0.0003

In Scenario 1 (Average Storm Frequency), the local historical average frequencies were used directly – providing a conservative forecast. Appendix B illustrates how Scenarios 2 and 3 were developed relative to Scenario 1.

The following numbers follow the FPSC methodology for the years requested and are the transmission Severe weather and non-severe weather data that are typically excluded from the "adjusted" data.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SAIDI	9.9	10.9	6.5	6.4	8.5	8.2	8.8	10.3	11.9	8.3
SAIFI	0.21	0.17	0.14	0.16	0.19	0.16	0.19	0.22	0.20	0.17

45. Please provide the Company's System SAIDI and SAIFI for transmission system outages only, excluding major storms, for the Company's Florida service area for each year since 2010.

Response:
The following numbers follow the FPSC methodology for the years requested and is the transmission non severe weather data that is typically excluded from the "adjusted" data.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SAIDI	8.9	10.8	6.3	6.3	8.4	8.2	8.5	10.2	11.7	8.3
SAIFI	0.19	0.17	0.13	0.15	0.19	0.16	0.18	0.22	0.20	0.17

46. Please provide the Company's SAIDI and SAIFI for distribution plus transmission outages, including major storms, for the Company's Florida service area for each year since 2010.

Response:
The following numbers follows the FPSC methodology for the "adjusted" SAIDI and SAIFI for the years requested plus the transmission outages for severe weather, non-severe weather, and distribution major storms data which are typically excluded from the "adjusted" numbers.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SAIDI	104.7	162.1	126.7	97.8	93.9	88.0	355.6	2,553.1	215.6	101.9
SAIFI	1.46	1.44	1.30	1.29	1.28	1.15	1.52	2.03	1.30	1.17

47. Please provide the Company's System SAIDI and SAIFI for distribution plus transmission outages, excluding major storms, for the Company's Florida service area for each year since 2010.

Response:

The following numbers follow the FPSC methodology for the "adjusted" SAIDI and SAIFI for the years requested plus the transmission non severe weather which is typically excluded from the "adjusted" numbers.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SAIDI	102.2	97.8	79.7	95.4	93.5	87.9	93.5	92.9	110.3	98.8
SAIFI	1.41	1.24	1.09	1.25	1.28	1.15	1.16	1.15	1.21	1.14

48. Please explain any factors unique to the Company's Florida service area that contribute to higher SAIDI or SAIFI performance in the Florida jurisdiction when compared to SAIDI or SAIFI performance by utilities in other regions.

Response:
Some factors that contribute to higher SAIDI and SAIFI compared to other regions are DEF's service area is more susceptible to extreme weather events (hurricanes and tropical storms) and non-extreme weather events (thunder storms and high winds) due to having more coastline than any other continental state and having the highest lightning volume of all other regions.

49. Please provide your cost/benefit analyses supporting each major component of the Company's proposed Storm Protection Plan ("SPP").

Response:
The cost/benefit analysis for each main program for the Company's proposed Storm Protection Plan is shown below. It reflects the "Probability of Damage" and "Consequence of Damage" prioritization methodology directly from the Guidehouse model over the 10 year-period of the proposed SPP. The cost/benefit analysis results shown do not include the additional and final level of asset prioritization that will occur by subject matter experts within the Distribution and Transmission business units. As stated in SPP Exhibit JWO-2, that portion of prioritization will use the model outputs to "determine the optimum deployment plan considering factors such as current projects in the area, critical customers, operational knowledge, and resource availability".

2018 EIA Distribution Reliability Statistics for Larger U.S. IOUs (Ranked by SAIDI w MED)

RANKING	Utility Name	State	Ownership	Number of Customers	SAIDI With MED	SAIFI With MED	CAIDI With MED	SAIDI Without MED	SAIFI Without MED	CAIDI Without MED
1	El Paso Electric Co	TX	Investor Owned	325,494	49.3	0.7	71.0	49.3	0.7	71.0
2	Tucson Electric Power Co	AZ	Investor Owned	528,355	51.4	0.8	65.9	0.0	0.0	-
3	Florida Power & Light Co	FL	Investor Owned	4,978,301	60.4	0.7	85.0	54.6	0.7	84.0
4	The Toledo Edison Co	OH	Investor Owned	301,949	62.2	0.6	104.8	55.7	0.6	98.5
5	Portland General Electric Co	OR	Investor Owned	875,224	88.0	0.5	169.2	88.0	0.5	169.2
6	Tampa Electric Co	FL	Investor Owned	775,102	95.8	1.2	80.5	81.5	1.2	70.9
7	NorthWestern Energy LLC - (MT)	MT	Investor Owned	360,376	103.0	1.1	95.4	103.0	1.1	95.4
8	Kansas Gas & Electric Co	KS	Investor Owned	328,524	105.9	1.1	96.3	101.1	1.1	96.2
9	Public Service Co of NM	NM	Investor Owned	527,072	107.3	1.0	109.1	107.3	1.0	109.1
10	Public Service Co of Colorado	CO	Investor Owned	1,383,852	112.6	1.0	110.4	97.9	1.0	99.9
11	Nevada Power Co	NV	Investor Owned	975,142	114.3	0.7	165.6	46.5	0.5	94.8
12	MidAmerican Energy Co	IA	Investor Owned	691,449	117.0	1.0	113.6	93.0	0.9	100.0
13	Wisconsin Public Service Corp	WI	Investor Owned	450,573	118.0	1.0	121.4	108.0	0.9	115.4
14	Wisconsin Electric Power Co	WI	Investor Owned	1,134,188	119.0	0.7	162.6	70.0	0.6	117.6
15	Commonwealth Edison Co	IL	Investor Owned	4,103,470	120.3	0.8	146.7	57.8	0.7	82.6
16	San Diego Gas & Electric Co	CA	Investor Owned	1,462,128	121.0	0.7	183.8	77.7	0.6	123.7
17	Hawaiian Electric Co Inc	HI	Investor Owned	304,965	123.4	1.3	93.1	111.9	1.3	89.3
18	PacifiCorp	UT	Investor Owned	917,739	123.7	1.1	117.7	123.7	1.1	117.7
19	Northern States Power Co - Minnesota	MN	Investor Owned	1,265,163	125.0	1.0	131.5	95.0	0.9	108.0
20	Public Service Co of Oklahoma	OK	Investor Owned	550,649	126.9	1.3	94.6	101.2	1.2	86.7
21	Idaho Power Co	ID	Investor Owned	532,420	128.8	1.1	120.3	121.5	1.1	114.7
22	Duquesne Light Co	PA	Investor Owned	598,295	133.0	0.9	141.5	89.0	0.8	106.0
23	Southern California Edison Co	CA	Investor Owned	5,126,985	136.8	0.9	156.5	71.3	0.7	99.5
24	Union Electric Co - (MO)	MO	Investor Owned	1,231,639	140.0	0.9	164.7	86.0	0.7	119.4
25	Delmarva Power	DE	Investor Owned	310,376	141.5	0.9	164.5	70.8	0.7	101.1
26	PacifiCorp	OR	Investor Owned	607,462	145.8	1.5	98.9	98.0	1.2	79.5
27	Indianapolis Power & Light Co	IN	Investor Owned	496,450	149.0	1.1	131.4	67.5	0.9	71.1
28	Arizona Public Service Co	AZ	Investor Owned	1,239,949	153.3	1.1	142.3	86.3	0.8	102.9
29	Westar Energy Inc	KS	Investor Owned	381,392	153.4	1.2	132.3	92.5	0.9	101.6
30	Oncor Electric Delivery Company LLC	TX	Investor Owned	3,502,276	153.5	1.3	114.5	78.0	0.8	97.5
31	Interstate Power and Light Co	IA	Investor Owned	486,689	157.2	1.0	152.6	93.9	0.9	99.9
32	Wisconsin Power & Light Co	WI	Investor Owned	486,689	157.2	1.0	152.6	93.9	0.9	99.9
33	Sierra Pacific Power Co	NV	Investor Owned	361,601	161.6	1.7	95.1	161.6	1.7	95.1
34	Dominion Energy South Carolina, Inc	SC	Investor Owned	732,903	165.9	1.8	92.2	96.2	1.4	70.2
35	CenterPoint Energy	TX	Investor Owned	2,517,201	178.4	1.6	110.2	140.2	1.4	102.4
36	Public Service Elec & Gas Co	NJ	Investor Owned	2,373,060	178.9	1.1	165.7	55.1	0.8	69.7
37	Oklahoma Gas & Electric Co	OK	Investor Owned	775,945	180.5	1.0	180.5	130.9	0.9	145.4
38	KCP&L Greater Missouri Operations Co.	MO	Investor Owned	326,479	181.7	1.2	147.7	89.8	0.9	94.7
39	Potomac Electric Power Co	MD	Investor Owned	560,152	189.2	1.0	184.7	61.9	0.8	76.9
40	Ohio Edison Co	OH	Investor Owned	1,040,109	189.5	1.3	142.4	107.7	1.1	101.1
41	Dayton Power & Light Co	OH	Investor Owned	587,473	194.6	1.1	170.7	104.1	0.9	114.4
42	AEP Texas Central Company	TX	Investor Owned	844,645	196.3	1.8	108.7	166.0	1.7	98.9

2018 EIA Distribution Reliability Statistics for Larger U.S. IOUs (Ranked by SAIDI w MED)

RANKING	Utility Name	State	Ownership	Number of Customers	SAIDI With MED	SAIFI With MED	CAIDI With MED	SAIDI Without MED	SAIFI Without MED	CAIDI Without MED
43	Consolidated Edison Co-NY Inc	NY	Investor Owned	3,464,959	201.0	0.2	1,020.1	19.8	0.1	165.2
44	Ameren Illinois Company	IL	Investor Owned	1,244,276	207.8	1.1	195.1	110.9	0.9	123.7
45	Rochester Gas & Electric Corp	NY	Investor Owned	377,943	216.7	1.0	218.9	80.4	0.8	107.2
46	Duke Energy Florida, LLC	FL	Investor Owned	1,794,724	225.0	1.4	163.0	111.0	1.2	92.5
47	Georgia Power Co	GA	Investor Owned	2,456,340	227.4	1.5	153.6	125.2	1.2	103.5
48	Ohio Power Co	OH	Investor Owned	1,480,292	255.6	1.6	162.3	218.4	1.5	149.4
49	Entergy Texas Inc.	TX	Investor Owned	459,199	259.2	1.8	146.4	224.2	1.7	134.7
50	Indiana Michigan Power Co	IN	Investor Owned	464,619	262.8	1.3	206.0	175.7	1.1	159.6
51	Virginia Electric & Power Co	VA	Investor Owned	2,482,946	266.8	1.5	172.2	149.6	1.3	114.8
52	United Illuminating Co	CT	Investor Owned	333,861	267.0	1.2	228.2	59.0	0.6	93.7
53	Entergy Louisiana LLC	LA	Investor Owned	1,100,782	274.3	1.8	148.8	207.9	1.6	127.7
54	Alabama Power Co	AL	Investor Owned	1,476,907	278.6	1.4	194.8	113.2	1.0	108.3
55	Pennsylvania Electric Co	PA	Investor Owned	580,198	287.1	2.1	135.7	216.5	1.9	116.3
56	Cleveland Electric Illum Co	OH	Investor Owned	731,388	296.1	1.3	236.5	126.4	1.0	130.4
57	Pacific Gas & Electric Co.	CA	Investor Owned	5,547,929	301.6	1.2	256.7	126.3	1.1	117.1
58	Duke Energy Ohio Inc	OH	Investor Owned	725,829	317.0	1.5	205.8	143.0	1.2	124.3
59	Entergy Mississippi LLC	MS	Investor Owned	455,640	320.1	1.8	177.1	254.2	1.6	155.4
60	Atlantic City Electric Co	NJ	Investor Owned	535,560	325.3	1.3	244.6	76.4	0.9	84.9
61	Duke Energy Indiana, LLC	IN	Investor Owned	836,411	366.0	1.5	252.4	156.0	1.1	147.2
62	Public Service Co of NH	NH	Investor Owned	528,668	386.8	1.9	205.3	119.9	1.1	112.2
63	PPL Electric Utilities Corp	PA	Investor Owned	1,422,558	393.3	1.0	374.9	80.6	0.7	110.3
64	Niagara Mohawk Power Corp.	NY	Investor Owned	1,643,827	396.2	1.5	259.1	147.0	1.1	138.1
65	West Penn Power Company	PA	Investor Owned	716,367	400.1	1.4	278.2	170.6	1.2	148.0
66	Consumers Energy Co	MI	Investor Owned	1,813,361	406.8	1.3	314.1	200.9	1.0	197.5
67	Kentucky Utilities Co	KY	Investor Owned	536,063	411.3	1.3	307.7	100.1	0.9	107.7
68	Baltimore Gas & Electric Co	MD	Investor Owned	1,286,804	432.2	1.3	326.2	94.9	1.0	99.5
69	Puget Sound Energy Inc	WA	Investor Owned	1,148,866	434.0	1.5	285.5	145.0	1.0	146.5
70	Entergy Arkansas LLC	AR	Investor Owned	722,846	448.5	1.9	232.7	297.2	1.7	170.8
71	DTE Electric Company	MI	Investor Owned	2,191,374	485.3	1.4	357.9	177.2	1.0	170.2
72	Louisville Gas & Electric Co	KY	Investor Owned	420,114	490.7	1.5	331.1	85.7	0.9	97.4
73	Monongahela Power Co	WV	Investor Owned	388,704	524.8	2.5	209.9	423.3	2.3	182.3
74	The Narragansett Electric Co	RI	Investor Owned	492,421	594.8	1.6	378.8	65.1	1.0	65.0
75	Central Maine Power Co	ME	Investor Owned	635,107	633.3	2.6	239.9	235.8	1.9	127.5
76	PECO Energy Co	PA	Investor Owned	1,625,072	641.9	1.5	425.1	87.9	0.9	97.7
77	Duke Energy Carolinas, LLC	SC	Investor Owned	668,844	656.0	1.8	360.4	240.0	1.3	187.5
78	Connecticut Light & Power Co	CT	Investor Owned	1,271,056	780.0	1.3	604.7	81.0	0.7	111.0
79	Massachusetts Electric Co	MA	Investor Owned	1,301,417	790.7	1.5	542.0	122.3	1.0	120.9
80	Duke Energy Carolinas, LLC	NC	Investor Owned	1,910,497	910.0	1.8	505.6	203.0	1.1	186.2
81	NSTAR Electric Company	MA	Investor Owned	1,430,397	970.0	1.7	577.4	85.0	0.8	102.4
82	Appalachian Power Co	WV	Investor Owned	422,611	1,067.8	3.1	343.1	693.9	2.7	256.5
83	Appalachian Power Co	VA	Investor Owned	531,820	1,247.1	2.4	517.5	426.5	1.8	238.8
84	Central Hudson Gas & Elec Corp	NY	Investor Owned	304,381	1,257.7	2.6	483.7	182.7	1.5	121.8
85	New York State Elec & Gas Corp	NY	Investor Owned	891,168	1,260.2	2.3	550.3	155.4	1.2	130.6
86	Jersey Central Power & Lt Co	NJ	Investor Owned	1,112,634	1,291.8	2.2	594.7	161.6	1.4	119.1
87	Metropolitan Edison Co	PA	Investor Owned	565,359	1,354.1	2.0	675.7	161.5	1.2	131.9
88	Gulf Power Co	FL	Investor Owned	462,983	2,826.8	2.5	1,149.1	124.3	1.4	91.4
89	Duke Energy Progress (NC)	NC	Investor Owned	1,398,206	3,679.0	3.0	1,230.4	165.0	1.4	122.2

The survey does not specifically ask about SAIDI and SAIFI. Instead, The CX Monitor measures customer satisfaction with core experiences (PQ&R, Billing & Payment, and Price/Value) as well as any of 11 potential experiences including 'Outage' which customers may have experienced in the past 12 months. All customers provide a score for relevant experiences using a '0-10' scale. 'Net Satisfaction' scores are reported and = '% Customers Rating the Experience a 9 or 10' MINUS '% Customers Rating the Experience a 0 through 6'.

With regard to service reliability, the PQ&R and Outage questions ask: 'How satisfied are you with the reliability of the electric service Duke Energy provides?' and 'How satisfied were you with the way Duke Energy handled your power outage?' As shown in the response to POD Question 19, Duke Energy Florida customers recently provided the following Net Satisfaction ratings:

- **'Power Quality & Reliability' Net Satisfaction:**
  - January 2020 – 61.8
  - February 2020 – 61.6
  - March 2020 – 67.2
- **'Outage' Net Satisfaction:**
  - January 2020 – 47.3
  - February 2020 – 48.2
  - March 2020 – 51.4

120. Please provide the results from any and all surveys conducted by and on behalf of the Company to determine the optimal level of service reliability (e.g., SAIDI and SAIFI) desired by customers who take service at transmission voltages.

Response:
Please see DEF's response to OPC ROG 3- 119. Surveys do not differentiate by voltage.

121. Please provide the results from any and all surveys conducted by and on behalf of the Company to determine the number of customers that are willing to accept lower levels of service reliability or periodic interruptions in exchange for electric rate discounts.

Response:
The company has not administered such a survey.

122. Please identify the number of instances in the last ten calendar years in which the Company's retail customers have submitted formal complaints with the Commission regarding the Company's distribution or transmission service reliability and briefly describe the resolution of such complaints.

Response:
Subject to and without waiving DEF's objection contemporaneously filed with this request, please see the number of Formal Commission Complaints in the last 10 years, as outlined in the Annual Reliability Report below:

Complaint Category	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Outages - Momentary	24	18	10	27	15	12	8	6	8	7
Outages - Frequent	46	21	29	35	53	38	39	35	77	47
Outages - Extended	4	12	2	2	5	5	2	23	10	13
Voltage	2	4	0	3	2	3	5	2	3	7
Equipment/Facilities	7	12	9	6	5	4	4	10	16	13
Tree Trimming	10	11	8	9	9	6	6	6	6	8
Safety	2	1	0	2	1	0	0	0	0	0
Total	**95**	**79**	**58**	**84**	**90**	**68**	**64**	**82**	**120**	**95**

Upon receipt of a FPSC complaint, Duke Energy Florida (DEF) initiates the following actions:

- DEF contacts the customer to acknowledge the complaint and within 15 business days, DEF will provide the FPSC with a detailed written response of the actions taken to resolve the customer's reliability concerns.
- DEF will remain in communication with the customer throughout the resolution process, providing timely updates and final resolution.
- DEF's resolution process includes partnering with the Power Quality team and/or Vegetation Management team to review and investigate the reliability complaint, and to determine next steps.
  - Next steps include a review momentary and extended outages, along with previous reliability and/or voltage issues for the premise.
  - A patrol is performed to identify any equipment, facilities, or vegetation concerns.
  - DEF may also determine if additional steps are needed which includes completing a voltage check at the premise and installing a recording voltage meter, depending on the outcome of the reliability review.
  - Once DEF determines the cause of the reliability concern, priority actions are taken which may include the following:
    - Tree trimming
    - Equipment repair/replacement
    - Equipment adjustments
    - Additional monitoring

Response:

The reliability-related complaints DEF has received each of the last 10 years are reported in DEF's annual reliability reports, available from the Commission's website. The totals are summarized below.

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
204	221	204	179	192	187	173	420	271	251

21. Please provide the documents containing your documentation of the total number of complaints due to transmission service reliability problems in the Company's Florida service area for each of the last ten years.

Response:
Please see DEF's response to OPC's Request for Production of Documents number 20. Transmission and Distribution complaints are not separated internally.

22. Please provide copies of any tariffs or terms and conditions available to customers in the Company's Florida service area that provide for customers to obtain higher than standard transmission or distribution service reliability, and identify the number of customers in each rate class who requested and were served under such tariffs or terms for each of the last five calendar years.

Response:
Please see that attached documents bearing bates number 2020069-DEF-000279 through 20200069-000376. DEF has the option for premium distribution service (PDS) offered on all non-residential tariffs per section 2.05 of the General Rules and Regulations Governing Electric Service. The applicable sections of the General Rules and Regulations and the specific tariffs have been highlighted in the provided tariff copies.

All DEF customers that were served using PDS offered in the tariffs in the last five calendar years were served on the General Service Demand (GSD) rate class. See below for the annual count since 2015.

2015: 26 PDS customers; All GSD
2016: 26 PDS customers; All GSD
2017: 27 PDS customers; All GSD
2018: 29 PDS customers; All GSD
2019: 30 PDS customers; All GSD

23. Please provide the documents containing the cost/benefit analyses supporting each major component of your proposed Storm Protection Plan ("SPP") as required by Rule 25-6.030(3) and as requested in Citizens Second Set of Interrogatories, No. 49, including all

CERTIFICATE OF SERVICE
Docket No. 20200069-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 26th day of May, 2020, to the following:

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