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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20200067-EI

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

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

Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Gulf Power Company.
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DOCKET NO. 20200071-EI

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

Storm Protection Plan Cost Recovery Clause.
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VOLUME 1

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:	CHAIRMAN GARY F. CLARK COMMISSIONER ART GRAHAM COMMISSIONER JULIE I. BROWN COMMISSIONER DONALD J. POLMANN COMMISSIONER ANDREW GILES FAY
DATE:	Monday, August 10, 2020
TIME:	Commenced: 1:00 p.m. Concluded: 2:15 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	DEBRA R. KRICK Court Reporter

PREMIER REPORTING
114 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
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APPEARANCES:

JAMES D. BEASLEY, J. JEFFRY WAHLEN, and MALCOLM N. MEANS, ESQUIRES, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company (TECO).

DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701; MATTHEW R. BERNIER, ESQUIRE, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301-7740, appearing on behalf of Duke Energy Florida, LLC (DEF).

RUSSELL A. BADDERS, ESQUIRE, One Energy Place, Pensacola, Florida 32520 and JASON A. HIGGINBOTHAM and JOHN T. BURNETT, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Gulf Power Company (Gulf).

CHRISTOPHER T. WRIGHT and JOHN T. BURNETT, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company (FPL).

JON C. MOYLE, JR. and KAREN PUTNAL, ESQUIRES, 118 North Gadsden Street, Tallahassee, Florida 32312, appearing on behalf of Florida Industrial Power Users Group (FIPUG).

APPEARANCES (CONTINUED):

JAMES W. BREW and LAURA WYNN BAKER, ESQUIRES, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, District of Columbia 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS).

J.R. KELLY, PUBLIC COUNSEL, and CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; PATRICIA A. CHRISTENSEN, A. MIREILLE FALL-FRY, and THOMAS A. (TAD) DAVID, ESQUIRES, OFFICE OF PUBLIC COUNSEL, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida (OPC).

STEPHANIE U. EATON, ESQUIRE, 110 Oakwood Drive, Suite 500, Winston-Salem, North Carolina 27103, and DERRICK PRICE WILLIAMSON and BARRY A. NAUM, ESQUIRES, 1100 Bent Creek Boulevard, Suite 101, Mechanicsburg, Pennsylvania 17050, appearing on behalf of Walmart Inc. (Walmart).

APPEARANCES (CONTINUED):

RACHAEL DZIECHCIARZ and CHARLES MURPHY, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission (Staff).

KEITH C. HETRICK, GENERAL COUNSEL; MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, advisor to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List		18
2-43	As identified on the Comprehensive Exhibit List		18
45-109	As identified on the Comprehensive Exhibit List		18

P R O C E E D I N G S

CHAIRMAN CLARK: Good afternoon. I will begin by calling this hearing to order.

Today is August 10th, 2020. And we will call this administrative order to order.

Would staff please read the notice?

MS. DZIECHCIARZ: By notice issued July 17th, 2020, this time and place has been set for an administrative hearing in Docket Nos. 20200067-EI, 20200069-EI, 20200070-EI and 20200071-EI to review the Storm Protection Plans, or SPPs, submitted by Tampa Electric Company, Duke Energy Florida, LLC, Gulf Power Company and Florida Power & Light Company pursuant to Section 366.96, Florida Statutes, and Rule 25-6.030, Florida Administrative Code.

In addition, by notice issued on July 31st, 2020, and subsequently amended on August 4th, 2020, this time and place has been noticed for an administrative hearing in Docket No. 20200092-EI, the Storm Protection Plan Cost Recovery Clause, or SPPCRC docket, to address the impacts to that docket.

CHAIRMAN CLARK: All right. Thank you, Ms. Dziechciarz.

Let's move on to appearances.

MS. DZIECHCIARZ: Chairman, there are five docs we are addressing today in this proceeding. We recommend that all appearances be taken at once. All parties should entered their appearances and declare the dockets that they are entering an appearance for. After all of the parties make their appearances, staff will make theirs.

CHAIRMAN CLARK: Okay. We are going to take appearances. I will call the company name, and would the representatives please state your persons that will be appearing?

I will begin with Tampa Electric Company.

MR. MEANS: Good afternoon, Commissioners.

This is Malcolm Means with Ausley McMullen appearing for Tampa Electric Company. I would also enter an appearance for Jim Beasley and Jeff Wahlen. And we are appearing in Dockets No. 20200067-EI and 20200092-EI.

Thank you.

CHAIRMAN CLARK: Thank you, Mr. Means.

Duke Energy.

MR. BERNIER: Afternoon, Commissioners.

Matt Bernier for Duke Energy, making an appearance in Docket 20200069. I would also like to enter an appearance for Dianne Triplett for the same docket.

Thank you.

CHAIRMAN CLARK: Thank you, Mr. Bernier.

Gulf Power Company.

MR. BADDERS: Yes. Good afternoon.

This is -- this is Russell Badders on behalf of Gulf Power. Chris Wright is also entering an appearance for Gulf Power.

CHAIRMAN CLARK: Okay. Thank you, Mr. Badders.

Florida Power & Light.

MR. WRIGHT: Good afternoon, Commissioners.

This is Chris Wright on behalf of Florida Power & Light. Here with me today is John Burnett. We are entering an appearance on the 70 and 92 dockets on behalf of Florida Power & Light.

CHAIRMAN CLARK: Okay. Thank you, Mr. Wright.

Office of Public Counsel.

MS. FALL-FRY: Good afternoon. This is A. Mireille Fall-Fry entering an appearance for Docket No. 20200067 and 20200092. I would also like to enter an appearance for J.R. Kelly, Public Counsel.

MS. CHRISTENSEN: Good afternoon. This is Patty Christensen with the Office of Public

Counsel. I am entering an appearance in Dockets 20200071 and 20200092 for FPL.
MR. DAVID: Yes, this is Tad David from the Office of Public Counsel, entering an appearance in 0070 and 0092.
CHAIRMAN CLARK: Thank you, Tad.
MR. REHWINKEL: Commissioner, Charles Rehwinkel with the Office of Public Counsel, entering an appearance in all dockets.
Thank you.
CHAIRMAN CLARK: Thank you, Mr. Rehwinkel.
All right. Moving on to Florida Industrial Power Users Group. Ms. Putnal, we have no volume.
MS. PUTNAL: Thank you.
Karen Putnal on behalf of Florida Industrial Power Users Group, entering an appearance in all five dockets. I would also like to enter an appearance for Jon Moyle.
Thank you.
CHAIRMAN CLARK: Thank you very much.
PCS, Mr. Brew.
MR. BREW: Yes, good afternoon.
For PCS phosphate, James Brew. I would also like to note an appearance for Laura Wynn Baker, and we are participating in the 0069 docket.

CHAIRMAN CLARK: Thank you Mr. Brew.
Walmart.
MS. EATON: Hi. This is Stephanie Eaton. I am entering an appearance on behalf of Walmart, along with Derrick Williamson, in all five dockets.
CHAIRMAN CLARK: Okay. Thank you.
Commission staff.
MS. DZIECHCIARZ: I am Rachael Dziechciarz, and I would also like to make an appearance for Charles Murphy and Shaw Stiller.
CHAIRMAN CLARK: Thank you.
MS. HELTON: And finally, Mr. Chairman, Mary Anne Helton here as your advisor for all of the dockets, along with your General Counsel, Keith Hetrick.
CHAIRMAN CLARK: All right. Thank you very much.
Is there anyone that we have overlooked? Anyone to register an appearance?
MR. HIGGINBOTHAM: Yes. Good afternoon. This is Jason Higginbotham. I would like to enter an appearance on behalf of Gulf Power Company.
Thank you.
CHAIRMAN CLARK: Okay. Thank you, Mr. Higginbotham.

Anyone else?

All right. Let's move into preliminary matters. Staff, are there any preliminary matters to discuss?

MS. DZIECHCIARZ: Yes, Chairman Clark, there are a number of preliminary matters to be addressed today. The first is related to our remote hearing and the COVID-19 related notices. The second is our proposed plan for addressing the three pending motions for settlement agreement, and the associated motion filed by TECO in their SPPCRC docket, and we also, as a preliminary matter, will be moving the stipulated comprehensive exhibit list and testimony into the record.

So to begin, as we all know, State buildings are currently closed to the public, and other restrictions on gatherings remain in place due to COVID-19. Accordingly, this hearing is being conducted remotely, and all parties and witnesses will present argument and testimony by communications media technology.

Members of the public who want to observe or listen to this hearing may do so by accessing the live video broadcast, which they are hopefully doing now, which is available from the Commission website. Upon completion of the hearing, this archived video will also be made available.

Each person participating today needs to keep their phone or device muted when they are not speaking, and only unmute when they are called upon to speak. If they do not keep their phone muted, or put their phone on hold, they may be disconnected from the proceeding and will need to call back in.

And just a reminder, if you do -- if that does happen, please call back in on the newer phone number, or using the newer link that was provided just a few minutes ago.

Also, telephonic participants should speak directly into their phone and not use the speaker function.

Moving into the proposed plan for dealing with the three pending motions for settlement agreement and TECO's associated motion.

So as stated previously, each of the utilities has entered into a settlement agreement regarding a storm protection plan. If approved, the agreement will resolve all matters in the utility's storm protection plan docket, and depending on the agreement, may also resolve some or all of the matters in the utility's storm protection plan cost recovery docket. In addition, TECO has a motion to approve revised tariffs that is associated with its motion to approve settlement agreements.

Staff recommends that the Commission take up these matters after entering the stipulated exhibits and testimony into the record. We recommend that the Commission allow each of the parties to provide a brief statement regarding support or position on the settlement agreements to which it is a party, then provide an opportunity for the Commissioners to ask any questions related to the agreement, and then the Commission should take up each motion for deliberation.

So that we are all on the same page, the pending motions are the Gulf and FPL joint motion for expedited approval of stipulation and settlement agreement submitted on July 27th, 2020, in Docket Nos. 20200070-EI, 20200071-EI and 20200092-EI.

The second pending motion is the DEF joint motion for expedited approval of settlement agreement submitted on July 31st, 2020, in Docket No. 20200069-EI.

I would also like to note that this is the second motion for settlement agreement submitted by Duke Energy Florida. The first motion was submitted on July 17th, 2020, in both Duke's SPP and SPPCRC dockets. This motion is currently set to be taken up by the Commission on September 1st, 2020. So for today, we will only be addressing Duke's 7/31 motion for expedited settlement agreement.

The third pending motion on our list today is TECO's motion to approve stipulation and settlement agreement submitted on August 3rd, 2020, in Docket Nos. 20200067-EI and 20200092-EI.

Similarly, I would like to note that this is the second motion for settlement agreement submitted by TECO. The first agreement was submitted on April 27th, 2020, which was filed in both the TECO SPP docket, TECO -- the SPPCRC docket, as well as another -- a number of other impacted dockets -- dockets.

This motion was approved by Commission Order No. PSC-20200224-AS-EI issued on June 30th, 2020. So again, we will only be taking up TECO's second motion for settlement agreement submitted on August 3rd today.

Finally, the plan is to take up TECO's motion to approve revised tariffs submitted on July 31st, 2020, in Docket No. 20200092-EI if the 8/3 TECO settlement agreement is approved.

Some of the parties have brought a witness to answer any technical questions that the Commissioners may have which the parties representatives cannot answer. Staff recommends that if a Commissioner wishes to ask a party a question, all of that party's witnesses should be sworn in as a panel at that time. If requested by the Commission, the witnesses are available to provide a brief summary regarding their position prior to answering questions.

The final preliminary matter that we have is moving the stipulated comprehensive exhibit list and testimony into the record -- into the record, excuse me.

Staff has compiled a stipulated comprehensive exhibit list which includes the prefiled exhibits attached to the witnesses' testimony in this case. The list has been provided to the parties, the Commissioners and the court reporter. This list is marked as the first hearing exhibit, and other exhibits should be marked as set forth in this docket.

(Whereupon, Exhibit No. 1-109 were marked for identification.)

CHAIRMAN CLARK: Staff, would you like to move these into the record?

MS. DZIECHCIARZ: Yes, I would.

Staff requests that the comprehensive exhibit list marked as Exhibit No. 1 be entered into the record, please.

CHAIRMAN CLARK: Exhibit No. 1 is entered.

(Whereupon, Exhibit No. 1 was received into evidence.)

MS. DZIECHCIARZ: Staff also requests that Exhibit Nos. 2 through 109 be moved into the record as set forth in the comprehensive exhibit list, with the exception of Exhibit No. 44, which was withdrawn pursuant to Prehearing Order No. PSC-2020-0275-PHO-EI.

CHAIRMAN CLARK: All right. Are there any objections to the entry of these exhibits into the record?

Seeing none, exhibits are entered, with the exception of No. 44, which is withdrawn.

(Whereupon, Exhibit Nos. 2-43 & 45-109 were received into evidence.)

CHAIRMAN CLARK: All right. Moving on to

witness testimony.

MS. DZIECHCIARZ: Thank you, Chairman.

The witnesses who have prefiled testimony have been excused from this proceeding. The parties have stipulated to entering in the direct, rebuttal and intervenor testimony submitted in Docket Nos. 20200067-EI, 20200069-EI, 20200070-EI and 20200071-EI.

CHAIRMAN CLARK: Okay. We are going to move all of the stipulated witness testimony into the record at this time.

(Whereupon, prefiled direct testimony of Gerry R. Chasse was inserted.)

INTRODUCTION

Q. Please state your name, address, occupation and employer.

A. My name is Gerard R. Chasse. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company (“Tampa Electric” or “the Company”) as Vice President, Electric Delivery.

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

A. My duties and responsibilities include the oversight of all functions within Tampa Electric’s Electric Delivery Department including the planning, engineering, operation, maintenance and restoration of the transmission, distribution and substation systems; operation of the distribution and energy control centers; administration of tariffs and compliance; execution of the Company’s Transmission and Distribution (“T&D”) strategic solutions including advanced metering infrastructure, outdoor and streetlight LED conversion project, and advanced distribution management system; line clearance activities; warehouse and stores; and fleet and equipment. As it relates to this filing, I am responsible for the development of Tampa Electric’s Storm Protection Plan and the safe, timely, and efficient implementation of that Plan.

Q. Please describe your educational background and professional experience?

A. I received a Bachelor of Science degree in electrical engineering from the University of Maine in 1990 and became a licensed professional engineer in 1996. I have held numerous positions of increasing responsibility in Bangor Hydro Electric and its successor, Emera Maine, including Substation Engineer, Planning Engineer, Substation Operations Supervisor, Manager of Engineering, Manager of Assets, Project Manager for an international transmission line, Vice-President of Operations, Executive Vice-President, and President of Emera Maine from 2010 through 2015. In 2015 and 2016, I was Vice-Chair of the Emera Maine Board. My position was also focused on renewable strategy, grid modernization strategy, and customer strategy for Emera companies from 2015 to 2016 before my current role.

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

A. The purpose of my direct testimony is to present, for Commission review and approval, Tampa Electric's 2020-2029 Storm Protection Plan. I will introduce the company's Plan and provide a description of how implementation of the company's proposed 2020-2029 Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather and enhance reliability by strengthening the company's infrastructure. I will also offer a description of the company's service area and describe the process used to develop the Plan, as well as a description of how the Plan's implementing Programs were selected and prioritized. Finally, I will describe the alternatives to implementation of the Plan that the company considered.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am. Exhibit No. GRC-1, entitled, "Tampa Electric's 2020-2029 Storm Protection Plan", was prepared under my direction and supervision. This Exhibit details the company's plans to implement the Storm Protection Plan Rule.

Q. Will any other witnesses testify in support of Tampa

Electric’s Proposed Storm Protection Plan?

A. Yes. Regan B. Haines will testify about six of the eight Programs contained within the Storm Protection Plan. John H. Webster will testify regarding the company’s planned Vegetation Management Program and Transmission Access Program. Jason D. De Stigter will testify regarding the methodology to select and prioritize Storm Protection Programs and Projects. Finally, A. Sloan Lewis will testify regarding the estimated annual jurisdictional revenue requirement for the Plan and the estimated rate impacts for each of the first three years of the Plan.

TAMPA ELECTRIC’S SERVICE AREA

Q. Please describe Tampa Electric’s service area and how many customers does the company serve?

A. Tampa Electric’s Service Area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties. Tampa Electric provides service to 794,953 retail electric customers as of January 1, 2020.

Q. Do you have a map of Tampa Electric’s service area?

A. Yes, a map of Tampa Electric's service area is included below.

Q. How many structures does the company's transmission, distribution electrical system have?

A. The company has 1,350 miles of overhead facilities, including 25,416 transmission poles. The company's transmission system also includes approximately nine miles of underground facilities. The company's distribution system has 6,300 miles of overhead facilities, including approximately 404,000 poles. The company currently has approximately 5,100 circuit miles of underground facilities. The company currently has 216 substations.

Q. In the development of the company's Storm Protection Plan, did Tampa Electric place a higher priority on any areas of the company's service area for hardening or enhancement projects contained in the company's Storm Protection Plan, and if so, please explain the reasoning for this prioritization?

A. No. Each of the Programs and each of the Projects are prioritized based on modeled cost/benefit ratios. For example, Tampa Electric used the 1898 & Co. modelling tool to assist in the prioritization of individual Projects and to set the overall Program funding levels for the Distribution Lateral Undergrounding Program. In the initial years of the Program, Projects were selected taking into account modeling results in conjunction with operational and design efficiency which include some level of geographic diversity.

Q. In the development of the company's Storm Protection Plan, were there any areas of the company's service area that Tampa Electric determined would be impractical, unfeasible or imprudent for hardening or enhancement projects within the company's Storm Protection Plan, and if so, please explain the reasoning for this reasoning?

A. No. There are no areas of the company's service area where it would impractical, unfeasible or imprudent to harden. All components of the transmission and distribution system can be hardened to achieve resiliency benefits.

PROCESS TO DEVELOP THE 2020-2029 STORM PROTECTION PLAN

Q. Please explain Tampa Electric's systematic approach to achieve the objectives of reducing restoration costs and outage times and enhancing reliability, and how that approach was utilized to develop the company's proposed Storm Protection Plan?

A. In response to the new requirement to develop a comprehensive SPP, Tampa Electric evaluated its existing storm hardening activities and searched for potential additions and improvements. The company began by consulting its internal subject-matter experts to identify major causes of storm-related outages and major barriers to restoration following storms. The company then engaged three outside consultants to help it evaluate potential solutions and to assist with estimation of costs and benefits for those solutions. The result is a Plan that includes several newly developed incremental Storm Protection Programs, Projects and activities that resulted from the thorough and comprehensive analysis. These new Programs, as well as the company's legacy Storm Hardening Plan activities, are described more fully in Tampa Electric's Storm Protection Plan. This approach is designed to fully achieve the goals, objectives and requirements of the Florida Legislature and the Commission's Rule.

Q. Did Tampa Electric incur any incremental costs in the development of the company's Storm Protection Plan?

A. Yes, Tampa Electric hired a program manager in the Energy Delivery Department to facilitate the company's Storm Protection Plan activities. The company also obtained the assistance of three consultants.

Q. What role did the three consultants play in the development of the company's Storm Protection Plan?

A. The three consultants assisted the company in the development of the Storm Protection Plan in the following three areas:

1. Performing project prioritization and benefits calculations for several of the company’s proposed Storm Protection Programs, including: (1) Distribution Lateral Undergrounding; (2) Transmission Asset Upgrades; (3) Substation Extreme Weather Hardening; (4) Distribution Overhead Feeder Hardening; and (5) Transmission Access Enhancements. This prioritization and cost-benefit analysis is described more fully in the Direct Testimony of Jason D. De Stigter.
2. Analyzing the company’s current vegetation management activities and developing a methodology for selecting and prioritizing incremental vegetation management activities. This analysis is described more fully in John H. Webster’s Direct Testimony.
3. Performing an automation analysis for the 22 prioritized distribution circuits for the Overhead Feeder Hardening Program for 2020-2022.

Q. Would you explain why the company chose to obtain the consulting services for assistance with the development of the Storm Protection Plan?

A. The company chose to obtain consulting services for assistance with the development of the Storm Protection Plan for a number of reasons including: (1) it did not have the incremental resources available to continue its existing operations and meet the filing requirements required by the Rule; and (2) it did not have the sophisticated modeling tools necessary to perform a thorough and detailed benefits and prioritization analysis for the Vegetation Management Program or the other five Programs listed above.

TAMPA ELECTRIC’S 2020-2029 STORM PROTECTION PLAN

Q. Would you describe Tampa Electric’s 2020-2029 Storm Protection Plan?

A. Tampa Electric’s Storm Protection Plan is designed with the primary objective of enhancing the resiliency and reliability of its transmission and distribution systems during extreme weather events. Over the next ten years, Tampa Electric will build upon the success of its existing Storm Hardening Plan to materially improve resiliency through targeted investments in the following

Programs: (1) Distribution Lateral Undergrounding; (2)Vegetation Management; (3) Transmission Asset Upgrades; (4)Substation Extreme Weather Hardening; (5) Distribution Overhead Feeder Hardening; (6) Transmission Access Enhancement; (7) Infrastructure Inspections; and (8) Legacy Storm Hardening Initiatives. These Programs will minimize the impact of severe weather by hardening Tampa Electric’s infrastructure.

Q. Will Tampa Electric’s Storm Protection Plan further the objectives of Section 366.96 of the Florida Statutes?

A. Yes. We developed a Storm Protection Plan based on a rigorous analysis of possible methods to achieve the goals of Section 366.96 of the Florida Statutes. The goal of our analysis was to identify those activities that deliver the greatest storm resiliency and reliability benefits for the lowest cost. We believe that the company’s Plan will deliver significant resiliency benefits, reliability benefits and reduced outage times to our customers in a cost-effective manner.

Q. How is Tampa Electric Company’s Plan designed to deliver those benefits?

A. Tampa Electric's Storm Protection Plan is comprised of four new and four currently ongoing Storm Protection Programs. Four of these Storm Protection Programs are comprised of individual Projects. In addition, the company plans to incorporate existing activities from its 2019-2021 Storm Hardening Plan into the new 2020-2029 Storm Protection Plan. This will result in overall regulatory and business efficiency in managing one program rather than two.

Q. Would you describe the Programs in Tampa Electric's Storm Protection Plan?

A. Tampa Electric separated the three main requirements of the Storm Protection Statute – overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management – into eight distinct Programs. The Programs are as follows:

- **Distribution Lateral Undergrounding**
- **Vegetation Management**
- **Transmission Asset Upgrades**
- **Substation Extreme Weather Hardening**
- **Distribution Overhead Feeder Hardening**
- **Transmission Access Enhancement**

- **Infrastructure Inspections**
- **Legacy Storm Hardening Initiatives**

Q. Would you provide a brief description of each of the eight supporting Storm Protection Programs?

A. Yes, a brief description of each of the supporting Storm Protection Programs is below:

Distribution Lateral Undergrounding: Tampa Electric has approximately 4,900 miles of overhead lateral distribution lines. Tampa Electric does not currently have an organization or program for undergrounding laterals. Accordingly, the company will spend 2020 building an organization, developing and refining processes and acquiring formal arrangements with external resources to build and sustain this Program for the duration of the SPP. The company is targeting 10 miles of overhead to underground conversion in 2020 and targeting 100 – 110 miles of overhead to underground conversion from the start of the program in 2020 through the end of 2021. Beginning in 2022, the company plans to underground 100 miles or more annually.

The company and its consultant, 1898 & Co., determined the priority of these laterals through use of a robust modeling tool. The primary factor in prioritizing undergrounding Projects is reliability performance during extreme weather events. To illustrate, approximately 55 percent of all outages are caused by 30 percent of the company's lateral distribution lines. The prioritization method also gives due regard to the distribution of Projects across Tampa Electric's service area. All targeted laterals served by the same feeder will be undergrounded at once for efficiency in construction and in future storm response.

Vegetation Management: The company's Vegetation Management Program is comprised of four components: (1) existing trim cycles; (2) supplemental distribution trimming; (3) inspection-based mid-cycle trimming; and (4) reclamation of the 69kV transmission system.

The company currently implements a four-year effective distribution vegetation management cycle. Over a four-year period, 100 percent of the approximately 6,300 miles of distance of overhead lines are targeted to be cleared with due regard to circuit performance. Additionally, over the past three years, approximately $1.7M per year of reactionary trim has been performed. Reactionary vegetation management is typically driven by customer requests or degraded circuit reliability performance, often in the latter half of a circuit's trim cycle due to specific species demonstrating faster growth cycles.

Additionally, for transmission circuits above 200kV, the company complies with FERC standards and employs strict two- and three-year cycles for transmission circuits operating at voltages below 200kV.

As part of its Storm Protection Plan, the company proposes three additional vegetation management initiatives with the purpose of enhancing its current cycle-based program specifically to increase resiliency. Those initiatives include supplemental distribution circuit vegetation management, inspection-based mid-cycle distribution vegetation management, and 69kV vegetation management reclamation work. Detailed modeling by the company's consultant, Accenture, demonstrates that an additional 700 miles of supplemental distribution trimming would achieve the greatest ratio of benefits to costs under extreme weather conditions. The mid-cycle vegetation management initiative is inspection-based and designed to eliminate trees and vegetation that pose a hazard to the distribution lines but can't effectively be eliminated within the four-year cycle. Finally, the 69kV reclamation project is designed to increase access to difficult-to-reach areas of the company's high voltage transmission system. Accessibility to transmission in rights of way is an important factor in the speed of restoration and significantly enhances overall system resiliency.

Transmission Asset Upgrades: Approximately 20 percent of Tampa Electric's 25,400 transmission poles are wood pole structures. This Program consists of the proactive replacement of all remaining wood pole structures on the company's transmission system. The company proposes to accelerate the replacement of those structures to non-wood material, typically steel or concrete, to enhance the resiliency of the transmission system during extreme weather events.

Tampa Electric utilized 1898 & Co.'s resilience-based modeling to develop the initial prioritization of Projects based on historical performance relative to criticality of the transmission line, reduction of customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. Technical and operational constraints like access and long-lead time permits were also accounted for in the development of priority.

This Program offers a high level of benefits, yet these benefits are highly dependent on the frequency of extreme weather events. The CMI reduction benefit for the Transmission Asset Upgrades Program is approximately 29 percent while the resulting restoration cost reduction benefit is approximately 90 percent after an extreme weather condition.

Substation Extreme Weather Hardening: This Program is designed to increase the resiliency of flood-prone critical substation equipment. It may include the installation of extreme weather protection barriers; installation of flood or storm surge prevention barriers; additions, modifications or relocation of substation equipment; modification to the designs of the company’s substations; or other approaches identified to protect against extreme weather damage in or around the company’s substations. Tampa Electric has approximately 59 substations that are at risk in the event of hurricane-related storm surge. The company plans to commission a study to assess the vulnerability of the top 20 of these

59 substations, which will result in a recommendation for the prioritization of future substation Projects and a recommendation for the tactics used to mitigate their vulnerabilities.

Distribution Overhead Feeder Hardening: The performance of three phase feeders is critical during extreme weather events. Tampa Electric's Distribution Overhead Feeder Hardening Program will include enhancements designed to increase resiliency, reliability, and flexibility of its three phase feeders including Distribution Feeder Strengthening and Distribution Feeder Sectionalizing and Automation.

Distribution Feeder Strengthening will incorporate design standards changes focused on the physical strength of the distribution infrastructure. The company will transition to using minimum Class 2 poles for all feeders and 3-phase laterals providing for longer life and increased overall strength.

Distribution Feeder Sectionalizing and Automation will enable the transfer of load to adjacent unfaulted feeders through the addition of new equipment such as breakers, reclosers, sectionalizers, sensors, relays, and communication equipment in addition to increased feeder capacity in some locations. Feeders will be divided into sections feeding smaller numbers of customers so that when faults occur on a feeder section, that section can automatically isolate from the remainder of the healthy system. These design and standards changes will increase the overall resiliency of the company's feeder distribution system to withstand all ranges of extreme weather events.

Transmission Access Enhancement: Ready access to the company's approximately 1,350 miles of transmission facilities is critical to the efficient and timely restoration of its transmission system under all types of conditions, including blue sky and extreme weather events. This Program is designed to ensure effective access to those facilities with the addition or enhancement of roads and rights of way. Access roads also enable more efficient maintenance of the rights of way, including vegetation management in and along those corridors. Adequate access roads eliminate the need for costly and time-consuming installments of matting to provide temporary access to critical infrastructure. This Program also includes the design and construction of 17 access bridges. Access bridges are critical for moving heavy equipment in and along transmission corridors, enabling efficient restoration, maintenance and repair of transmission structures.

Infrastructure Inspections: Infrastructure inspections are a foundational element of an asset management program. A clear understanding of the condition of distribution, substation, and transmission assets is a critical piece of asset performance under any conditions. Tampa Electric's Infrastructure Inspection Program is a comprehensive inspection program that combines the legacy Storm Hardening Plan initiatives of: Wood Pole Inspections, Transmission Structure Inspections, and the Joint Use Pole Attachment Audit.

The company's inspection programs drive decisions on whether to replace, repair or restore its wood pole transmission, distribution, and substation infrastructure as well as the company's understanding of whether unauthorized attachments may have overloaded that infrastructure. The company believes that these are core initiatives with demonstrated value. As a result, the company has not prepared a new cost-benefit analysis for these activities. These are existing programs and the company proposes to continue them at approximately historical spending levels.

Legacy Storm Hardening Initiatives: The final category of storm protection activities consists of those legacy Storm Hardening Plan Initiatives that are ongoing and well-established, and for which the company does not propose any specific Storm Protection Projects at this time. Tampa Electric will continue these activities because the company believes they are necessary utility activities, conform to good utility practice, and continue to offer the storm resiliency benefits identified by previous Commission orders which required the company to perform these activities. These activities are still mandated by the Commission and the associated initiatives are all integrated into the company’s ongoing operations. Historically, Tampa Electric has not performed a formal cost benefit analysis for these activities because they were mandated by the Commission. Most notable of these programs is Tampa Electric’s distribution pole replacement initiative. It starts with the company’s wood pole inspections and includes designing and constructing distribution facilities that meet or exceed the company’s current design criteria for the distribution system. The company will continue to appropriately address all poles identified through its Infrastructure Inspection Program and in accordance with the National Electric Safety Code for wood pole strength requirements.

Given that this is a reactive activity (poles are replaced or restored only when they fail an inspection), Tampa Electric concluded that it was not practical or feasible to identify specific distribution pole replacement Storm Protection Projects.

Q. Please explain how the implementation of the company’s proposed Storm Protection Plan will strengthen the company’s infrastructure to withstand extreme weather conditions through overhead hardening of electrical transmission and distribution facilities as required by Rule 25-6.030(3)(a)?

A. Implementation of the company’s Transmission Asset Upgrades and Distribution Overhead Feeder Hardening Programs will strengthen the company’s infrastructure to withstand extreme weather conditions through overhead hardening of electrical transmission and distribution facilities. These Programs include transmission pole upgrades from wood to primarily steel or concrete, and the overhead hardening of distribution facilities through both feeder strengthening and sectionalization and automation. Increasing the strength of overhead facilities increases the ability of the company's poles, conductors and fixtures to resist wind loading during extreme weather events as well as loading from vegetation contacts. Eliminating infrastructure failures significantly reduces outages and time to restore outages. Automatic switching during storm events is designed to minimize outage impact to approximately 400 or fewer customers depending on the characteristics of the circuit. Outage locations are sensed, isolated, and adjacent unfaulted sections of feeders can be reenergized.

Q. Please explain how the implementation of the company's proposed Storm Protection Plan will strengthen the company's infrastructure to withstand extreme weather conditions through undergrounding certain portions of electrical distribution lines as required by Rule 25-6.030(3)(a)?

A. Implementation of the company's Distribution Lateral Undergrounding Program will strengthen the company's infrastructure through undergrounding portions of its lateral distribution lines. Underground laterals are shielded from many of the potential harmful effects of extreme weather events resulting in a number of significant benefits to customers. Indeed, metrics from past extreme weather events clearly show that underground systems prove to be much stronger and more resilient. The Program will reduce the number and severity of customer outages during extreme weather events, reduce the amount of system damage during extreme weather, reduce the material and manpower resources needed to respond to extreme weather events, reduce the number of customer complaints from the reduction in outages during extreme weather events, and reduce restoration costs following extreme weather events.

Q. Please explain how the implementation of the company's proposed Storm Protection Plan will strengthen the company's infrastructure to withstand extreme weather conditions through vegetation management as required by Rule 25-6.030(3)(a)?

A. The implementation of the company's proposed Vegetation Management Program will strengthen the company's infrastructure to withstand extreme weather conditions through vegetation management initiatives. Trees are the leading cause of outages both during extreme weather events and normal operations. Three new vegetation management initiatives in addition to the company's existing cycles will reduce the potential for vegetation to come into contact with the company's distribution and transmission lines during extreme weather events.

Q. Please explain how the implementation of the company's proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions as required by Rule 25-6.030(3)(b)?

A. The implementation of the company's proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions through a comprehensive approach using eight specific Programs. The combination of five of the first six Programs were modeled, assessed and optimized using a sophisticated storm resilience model employed by the company's consultant 1899 & Co. The incremental vegetation management initiatives were developed through detailed analysis using Accenture's TTM model. The proposed Programs also underwent additional analysis performed by Tampa Electric. These analyses demonstrate there are significant benefits associated with these Programs including reduced restoration costs, reduced outages, and reduced restoration times. Further Program benefits will accrue in day-to-day operations.

Q. Please explain how the implementation of the company’s proposed Storm Protection Plan will improve overall service reliability and customer service as required by Rule 25-6.030(3)(b)?

A. The implementation of the company’s proposed Storm Protection Plan will improve overall service reliability and customer service. Each of the eight Storm Protection Plan Programs will not only meet the storm resiliency goals of the Rule and the statute, but will also have significant reliability benefits during blue sky operations. The Plan will result in reduced outages, both momentary and sustained, and reduced restoration times resulting in reduced operating and capital costs.

ESTIMATED COSTS OF STORM PROTECTION PLAN

Q. Did the company prepare an estimate of the annual jurisdictional revenue requirements for each year of the proposed Plan?

A. Yes. The estimated annual jurisdictional review requirements for each year of the proposed Storm Protection Plan are included in Section 7 of the company’s Storm Protection Plan. A full explanation of the detail of these jurisdictional revenue requirements and how they were calculated for each year of the proposed storm protection plan is included as Exhibit No. ASL-1, Document No. 1 within A. Sloan Lewis’s direct testimony in this proceeding.

ESTIMATED RATE IMPACTS OF STORM PROTECTION PLAN

Q. Did the company prepare an estimate of rate impacts for each of the first three years of the proposed storm protection plan for a typical residential, commercial and industrial Tampa Electric customer?

A. Yes. The estimated rate impacts for each of the first three years of the proposed Storm Protection Plan for a typical residential, commercial and industrial Tampa Electric customer are included in the table below. A full detail explanation of these rate impacts and how they were calculated for each of the first three years of the proposed Storm Protection Plan is included in A. Sloan Lewis’s direct testimony in this proceeding.

	Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
	Customer Class			
	Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2020	1.50	1.48	1.44	0.55
2021	2.22	2.21	2.14	0.84
2022	3.09	3.06	2.98	1.13
2023	4.12	4.07	3.95	1.46

IMPLEMENTATION ALTERNATIVES

Q. Did the company consider any implementation alternatives that would mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan?

A. Yes. The company considered and quickly rejected an alternative that involved no incremental storm protection activities. This alternative was quickly dismissed because it does not achieve the objectives of the statute, which are to further reduce restoration costs and outage times associated with extreme weather and to enhance reliability. The company engaged Accenture to evaluate several initiatives to enhance the company's vegetation management plans and performance. As part of this analysis, several increments of activity and spending were evaluated. The company selected the option that yielded the most customer benefits. Tampa Electric also worked with 1898 & Co. to perform a budget analysis, which demonstrated significantly increasing levels of net benefit from the $250 million to $1.5 billion budget scenarios. The company's planned investment level is at the optimal point before diminishing returns. Tampa Electric also considered and rejected some capital programs and projects including undergrounding distribution feeders, proactively upgrading wood distribution poles, and purchasing temporary transmission access solutions such as matting.

ADHERENCE TO F.A.C. RULES AND STATUTORY REQUIREMENTS

Q. Does the process utilized by Tampa Electric to establish its proposed Storm Protection Plan for the 2020-2029 period address the requirements of Rule 25-6.030, F.A.C.?

A. Yes. Under Rule 25-6.030(3), F.A.C., a utility's Storm Protection Plan must contain several specific categories of information. The table below shows where each category of information is located within the company’s Proposed Storm Protection Plan.

Tampa Electric's 2020-2029 Storm Protection Plan Adherence to Rule 25-6.030 F.A.C.	
Required Contents of Plan	**Section of the Storm PP**
25-6.030(3)(a)-(b)	Section 3 - SPP Overview
25-6.030(3)(c)	Section 1 - Tampa Electric’s Service Area
25-6.030(3)(d)1-4	Section 6 – Storm Protection Programs
25-6.030(3)(d)5	Section 3 – SPP Overview
25-6.030(3)(e)	Section 6 – Storm Protection Programs
25-6.030(3)(f)	Section 6.2 – Vegetation Management
25-6.030(3)(g)	Section 7 – Projected Costs and Benefits
25-6.030(3)(h)	Section 8 – Estimated Rate Impacts
25-6.030(3)(i)	Section 9 – Alternatives and Considerations
25-6.030(3)(j)	N/A (optional)

Q. Does Tampa Electric’s Storm Protection Plan further the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability set out in Section 366.96(3) of the Florida Statutes?

A. Yes. As my testimony demonstrates, the company's Storm Protection Plan will achieve these objectives by hardening the company's infrastructure and making it more resilient and reliable during extreme weather events.

CONCLUSIONS:

Q. Please summarize your direct testimony.

A. My testimony and the direct testimony of Regan B. Haines, A. Sloan Lewis, John H. Webster, and Jason D. DeStigter and the accompanying exhibits present and support Tampa Electric's proposed 2020-2029 Storm Protection Plan. This Plan was developed in a manner consistent with the requirements of Section 366.96, Florida Statutes and the implementing Rule 25-6.030, F.A.C., adopted by the Commission.

Q. Should Tampa Electric's proposed 2020-2029 Storm Protection Plan be approved?

A. Yes. Tampa Electric's proposed 2020-2029 Storm Protection Plan should be approved. The Plan contains all of the required contents set out in Rule 25-6.030, F.A.C. The Plan will also build on the benefits the company achieved through the prior Storm Hardening Plans and initiatives that were established by this Commission in 2007. Finally, the Plan will accelerate the company’s existing hardening efforts to achieve the objectives of Section 366.96(3) of the Florida Statutes by strengthening the company’s infrastructure to withstand extreme weather conditions, reducing restoration costs and outage times, and by improving overall reliability and customer satisfaction.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Regan B. Haines was inserted.)

INTRODUCTION:

Q. Please state your name, address, occupation and employer.

A. My name is Regan B. Haines. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Director, Asset Management, Project Management and System Planning.

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

A. My duties and responsibilities include the governance and oversight of all Energy Delivery transmission and distribution assets. I am also responsible for developing and executing strategy and priorities for Energy Delivery's overall network for system planning, reliability planning and system maintenance. In addition, I am responsible for Energy Delivery's capital planning and budgeting, large project management, system root cause analysis, and benchmarking.

Q. Please describe your educational background and professional experience.

A. I graduated from Clemson University in June 1989 with a Bachelor of Science degree in Electrical Engineering and again in December 1990 with a Master of Science degree in Electrical Engineering specializing in Power Systems Engineering. I have been employed at Tampa Electric since 1998. My career has included various positions in the areas of Transmission and Distribution Engineering and Operations.

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

A. The purpose of my direct testimony is to explain six of the eight Storm Protection Programs in the company's proposed 2020-2029 Storm Protection Plan ("SPP" or "Plan"). I will also describe the Storm Protection Projects associated with these Programs as applicable. My testimony will describe how the company's Plan complies with Rule 25-6.030(3) by providing all the information required for each of these six Programs and their implementing Projects.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I have prepared an exhibit entitled, "Exhibit of Regan B. Haines." It consists of four documents and has been identified as Exhibit No. RBH-1, which contains the following documents:

- Document No. 1 provides Tampa Electric's – Proposed 2020-2029 Storm Protection Plan Projected Costs versus Benefits by Program.
- Document No. 2 provides the Project Detail for the Distribution Lateral Undergrounding Program.
- Document No. 3 provides the Project Detail for the Transmission Asset Upgrades Program.
- Document No. 4 provides the Project Detail for the Distribution Overhead Feeder Hardening Program.

TAMPA ELECTRIC'S SERVICE AREA

Q. Are there any parts of Tampa Electric's service area that were prioritized for enhancement, or any areas where enhancement would not be feasible, reasonable or practical, under the six Programs described in your testimony?

A. No. The company did not exclude any area of the company's existing transmission and distribution facilities for enhancement under these Programs due to feasibility, reasonableness, or practicality.

TAMPA ELECTRIC’S 2020-2029 STORM PROTECTION PLAN

Q. Would you describe the Programs that support Tampa Electric’s Storm Protection Plan?

A. Tampa Electric’s proposed 2020-2029 Storm Protection Plan is comprised of eight distinct Programs. The Programs are:

1. Distribution Lateral Undergrounding
2. Vegetation Management
3. Transmission Asset Upgrades
4. Substation Extreme Weather Hardening
5. Distribution Overhead Feeder Hardening
6. Transmission Access Enhancement
7. Infrastructure Inspections
8. Legacy Storm Hardening Plan Initiatives

Q. You mentioned that you would be describing six of the eight Storm Protection Programs. Which Programs are you not describing?

A. I will not be describing the Vegetation Management or Transmission Access Enhancement Programs. The direct testimony of John H. Webster will cover those two Storm Protection Programs.

Q. How is your testimony organized?

A. For each Program I am describing, my testimony will explain how the company developed the information required by Rule 25-6.030(d)1-4, including: (1) a description of how the Program is designed to enhance existing transmission and distribution facilities, including an estimate of the resulting restoration in outage times and restoration costs; (2) actual or estimated start and completion dates of the program; (3) a cost estimate including capital and operating expenses; and (4) an analysis of costs and benefits.

Q. Will you testify regarding the information required by Rule 25-6.030(3)(d)5 – the criteria the company used to select and prioritize its proposed Storm Protection Programs?

A. No. The direct testimony of Gerard R. Chasse will describe the process Tampa Electric used to select and prioritize Programs.

Q. Will your testimony also address certain Storm Protection Projects?

A. Yes. In addition to explaining the required Program details, for each Program with Projects, my testimony will also explain how the company developed the required

Project-level details for the first year of the Plan, including: (1) actual or estimated construction start and completion dates; (2) a description of the affected facilities, including the number and type of customers served; and (3) a cost estimate including capital and operating expenses. My testimony will also describe how the company forecasted Project-level detail for the second and third years of the Plan.

Q. In the direct testimony of Gerard R. Chasse, he mentions that Tampa Electric used a consultant to assist with the development of the Plan. Why did Tampa Electric use this consultant?

A. Tampa Electric hired a consulting firm to help develop the company’s Plan. The company was looking for and found a consulting firm with expertise in the areas of T&D system hardening and cost-benefit analysis. The company also wanted an independent third-party review of our proposed SPP Programs and our methodology and prioritization approach. In addition, the company needed assistance with performing a thorough cost-benefit analysis. Tampa Electric selected 1898 & Co., part of Burns & McDonnell, which offered a very robust asset management modeling approach that would allow us to effectively analyze the storm impact risks associated with each component of the T&D system. Their model also gave us the capability to perform scenario analysis and ultimately prepare a robust cost-benefit analysis for several of our proposed Programs, including the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening and Distribution Overhead Feeder Hardening Programs. This analysis was critical as we prioritized Projects within each of these Programs and analyzed the costs and benefits of the Programs. In addition, 1898 gave us the ability to model the combined improvements from multiple Programs simultaneously, model multiple scenarios and optimize portfolio spend, and finally, gain confirmation that modeled benefits were appropriate, achievable and in range with the industry. The company believes that 1898 possessed the model needed to effectively perform the type of required analysis. Jason D. De Stigter from 1898 will provide direct testimony to more fully detail the approach taken for each of the Programs they supported.

Q. Please explain how Tampa Electric and 1898 & Co. prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather

Hardening and Distribution Overhead Feeder Hardening Programs?

A. The methodology used to develop the estimate of the reduction in outage times and restoration costs is addressed in detail in Jason D. De Stigter's direct testimony, but in general, 1898 developed a storm model that simulated 99 different storms scenarios and each scenario was modeled to identify which parts of the electric system are most likely to fail given each type of storm. The likelihood of failure is driven by the age and condition of the asset, the wind zone the asset is located within and the vegetation density around each conductor asset. 1898's Storm Impact Model also created an estimate of the restoration costs and Customer Minutes of Interruption ("CMI") associated with each potential Project for each storm scenario. Finally, the model calculated the benefit in terms of decreased restoration cost and reduced CMI if that Storm Protection Project were implemented per the company's hardening standards. This approach was repeated for every potential Storm Protection Project within each of these Programs. Finally, the estimated benefits of avoided restoration costs and outages were summed over the life of all hardened assets proposed for each Program during the 10 year plan and compared to the projected performance of the current assets or status quo. This comparison gave the company an estimated relative percentage reduction in restoration costs and outage times for each SPP Program. These estimates are included in my Exhibit No. RBH-1, Document No. 1 and are represented in terms of the relative benefit or improvement that the 10-year Program will provide. The benefits of a reduction in restoration costs and outage times are shown as a percentage improvement expected during extreme weather events or major event days when compared to the status quo.

Q. Please explain the methodology Tampa Electric used to prioritize the Projects the company is including in the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening and Distribution Overhead Feeder Hardening Programs?

A. The methodology used to develop the prioritization of Projects in these Programs is addressed in detail in Jason D. De Stigter's direct testimony. In general, we developed a Project cost estimate for each potential Project in our system that was based on several factors depending on the Program. For example, for distribution lateral undergrounding, factors such as the length of the line, location of the facilities (front or rear lot), number of transformers and customer services, etc. were considered. Secondly, we estimated the benefits each potential Project could provide by determining the savings of avoided restoration costs and the reduction in outage times or reduced customer minutes of interruption. The outage time reductions or savings were then converted to financial benefits utilizing the Department of Energy’s Interruption Cost Estimator (ICE) calculator. The ICE Calculator is an electric reliability planning tool designed for electric reliability planners to estimate interruption costs and/or the benefits associated with reliability improvements. Both benefits were combined and a cost benefit NPV was calculated for each potential Project. The NPVs were then used to rank or prioritize each Project within a given SPP Program.

Q. Does the final ranking of projects in the SPP strictly follow 1898’s prioritization?

A. No. The ranking serves as a guide, but the company will also apply operational experience and judgment when selecting Projects. This will help us to first, gain valuable experience early on in a Program by picking Projects that will ensure our procedures and approach are fully vetted with some of the less complex areas, and second, ensure that we are addressing all areas and communities equitably within our service territory.

Q. Did Tampa Electric prepare an analysis of the estimated costs and benefits of the Distribution Lateral Undergrounding, Transmission Asset Upgrades and Distribution Overhead Feeder Hardening Programs?

A. Yes. As I mentioned earlier, the company created cost estimates for each potential Project within each Program and then determined the benefit of each Project by using 1898's model to compare its performance before and after hardening. The benefits of a reduction in restoration costs and outage times for all of the Projects planned for each Program are shown as a percentage improvement expected during extreme weather events or major event days when compared to the status quo. A table comparing the estimated costs and benefits for each Program is included as Exhibit No. RBH-1, Document No. 1.

Q. You stated previously that the company compared the estimated costs and benefits of the Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening and Distribution Overhead Feeder Hardening Programs. How did the company use the Project-level costs and benefits described above to perform this comparison?

A. A detailed description of how the company used Project-level costs and benefits is addressed in Jason D. De Stigter's direct testimony. In general, a cost benefit NPV was developed for each potential Project which was then used to first determine its relative cost effectiveness and then to rank or prioritize Projects within each of the Programs. As mentioned earlier, this established a ranked Project listing that the company will use together with its business and operational judgement to determine when Projects will be implemented. Then the estimated costs and benefits for all Projects selected for each Program during the 2020-2029 plan period were aggregated to determine the total costs and benefits of each Program illustrated in my Exhibit No. RBH-1, Document No. 1.

Distribution Lateral Undergrounding

Q. Please provide a description of the Distribution Lateral Undergrounding Program.

A. The primary objective of Tampa Electric's Distribution Lateral Undergrounding Program is to increase the resiliency and reliability of the distribution system serving our customers during and following a major storm event by converting existing overhead distribution facilities to underground. Tampa Electric has approximately 6,250 miles of overhead distribution lines of which approximately 4,500 miles or 72% of the overhead distribution system are considered lateral lines or fused lines that branch off the main feeder lines. These lateral lines can be one, two or three phase lines and typically serve communities and neighborhoods.

Q. Did Tampa Electric work with 1898 to develop this Program?

A. Yes. The company worked with 1898 & Co. to prioritize all lateral lines utilizing a methodology that factors in the probability or likelihood of failure and the impact or consequence if a failure occurs during a major weather event. The company's distribution system contains 787 circuits or feeders and over 18,000 lateral lines. While the company has experience converting small areas of overhead distribution facilities to underground, this is the first time it will do so in this scale.

Q. What role does community outreach play in an undergrounding Program?

A. Community and customer outreach will be critical to the success of this Program. The company has accordingly placed an emphasis on this. A comprehensive outreach process will be developed to work cooperatively with property owners and neighborhoods impacted by this Program.

Q. How does the company plan to implement this Program?

A. This SPP Program will include a ramp up of overhead to underground conversion Projects in 2020 and 2021 to help establish the best overall process to maintain moving forward as this Program will continue past the ten-year horizon of this plan. Using the lateral line ranking as a guide, the company has created Projects that it will undertake each year. The company's plan is to develop an organization and structure that supports undergrounding 100-150 miles annually over the period 2022-2029. For plan year 2020 and 2021, the company plans to underground a total of 90-100 miles. This will include converting the existing overhead lateral primary, lateral secondary and service lines to underground.

Q. Please explain how Tampa Electric's Distribution Lateral Undergrounding Program will enhance the utility's existing transmission and distribution facilities?

A. This Program will provide many benefits including reducing the number of outages and momentary interruptions experienced during extreme weather events and day-to-day conditions, reducing the amount of storm damage, and reducing restoration costs. Historically, 94 percent of the outages occurring on the company's overhead distribution system originate from an event on an overhead distribution lateral line. In addition, a significant amount of a utility's restoration efforts deals with failures on lateral lines following major storm events. Many of the lateral lines in the older areas served are in the rear of customers' homes. These "rear lot" lateral lines are more likely to be impacted during a storm given vegetation and are more difficult to access and restore when they are impacted. Given that most of the failures experienced during major storm events, as well as day to day, originate on a lateral line, the primary objective of this Program is to underground the lateral lines that have the highest likelihood of failing and that also create the most significant impact during a major storm event. Comparatively, very few, if any outages have originated on underground facilities during the recently experienced named storms and only 6% during blue sky, day-to-day conditions. By undergrounding these overhead lateral lines, the risk of failure during a major storm event should be significantly mitigated.

Q. Did Tampa Electric prepare a list of Distribution Lateral Undergrounding Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

A. Yes, the list of Distribution Lateral Undergrounding Projects for 2020 and their associated starting and projected completion dates is included in Appendix A of the Plan and in my Exhibit No. RBH-1, Document No. 2. The company has also developed a very preliminary list of Projects for 2021. Given that this is a new Program for the company, the list of Projects selected for 2020 and 2021 were those identified from the prioritized list that will increase the company’s chances of early success while providing the most benefit to customers.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

A. Yes, a description of facilities affected by Project is included in my Exhibit No. RBH-1, Document No. 2. For this SPP Program, this will include a unique Project identifier, the number of and type of customers served by the facilities, and the number of miles of overhead line converted to underground for each Project.

Q. Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

A. Yes. The company has developed cost estimates for each Project within this Program for 2020 and 2021 and then totaled those estimates to derive the annual cost estimates for the Program. The company utilized several characteristics of the existing overhead facilities targeted for conversion to develop the cost estimates for each Project including, the number of phases involved, the length of the line, and location of the facilities (front or rear lot), etc. Based on the results of 1898's budget optimization model, the company then estimated the number of Projects it expects to complete in years 2022-2029 with average Project cost estimates to develop the annual Program costs in those years. The estimated costs for this Program include $8M in 2020, $80M in 2021 and then approximately $100M-$120M in each year 2022-2029. There were no incremental O&M costs associated with this Program. The table below sets out the estimated number of Projects and annual costs for 2020-2022.

	Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2020	24	$8.0
2021	281	$79.5
2022	316	$108.1

Transmission Asset Upgrades

Q. Please provide a description of the Transmission Asset Upgrades Program?

A. The main objective of this SPP Program is to address the vulnerability that our remaining wood transmission poles pose on the grid by systematically upgrading them to a higher strength steel or concrete pole. Tampa Electric plans to replace all existing transmission wood poles with non-wood material over the next ten years. The company has identified 131 of its existing 217 transmission circuits that have at least one existing wooden pole and will conduct replacement of those remaining transmission wood poles on an entire circuit basis.

Q. Please explain how Tampa Electric's Transmission Asset Upgrade Program will enhance the utility's existing transmission and distribution facilities?

A. Tampa Electric has over 1,000 miles of overhead transmission lines at voltage levels of 230kV, 138kV and 69kV. While the company experiences far fewer transmission outages and pole failures during major storm events than on the distribution system, an outage on the transmission system can have far greater impact and significance. The vast majority of these pole failures are associated with wood poles. Of the ten transmission poles replaced due to Hurricane Irma in 2017, nine were wooden poles with no previously identified deficiencies that would warrant the pole to be replaced under the existing Storm Hardening Plan Initiative. The company has already made significant progress in reducing storm-related transmission outages through implementation of Extreme Wind Loading design and construction standards. In the early 1990s, Tampa Electric changed its standards and began building all new transmission circuits with non-wood structures. Today, approximately 80 percent of Tampa Electric's transmission system is constructed of steel or concrete poles/structures. The remaining 20 percent, however, are still comprised of wood poles installed over 30 years ago.

Replacing the remaining wood transmission wood poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, and more robust, wind loading standards then required at the time of installation. This will greatly reduce the likelihood of a failure during a major storm event.

Q. Did Tampa Electric prepare a list of Transmission Asset Upgrades Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

A. Yes, the list of Transmission Asset Upgrades Projects for 2020 and their associated starting and projected completion dates is included in Appendix C of the Plan and in my Exhibit No. RBH-1, Document No. 3. The company is planning 21 projects in 2020 and has identified a very preliminary list of 35 projects for 2021. The remaining transmission circuits with wood poles were prioritized and scheduled for upgrade in the years 2022-2029.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

A. Yes, in my Exhibit No. RBH-1, Document No. 3, the description of the affected facilities for this Program include the total number of wood poles replaced on a circuit basis for each Project. Given that the high voltage transmission system is designed to transmit power over long distances to end-use distribution substations, Tampa Electric does not attribute customer counts directly to individual transmission lines.

Q. Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

A. Yes. The company has developed cost estimates for each Project within this Program for 2020 and 2021 and then totaled those estimates to derive the annual cost estimates for the Program. The company utilized its experience of average costs to upgrade a wood transmission pole to non-wood and the number of poles associated with each Project to develop the cost estimates. The company then estimated the number of Projects it expects to complete in years 2022-2029 with average Project cost estimates to develop the annual Program costs in those years. The estimated costs for this Program include $5.6M in 2020, $15.2M in 2021 and then approximately $15M in each year 2022-2029. There were no incremental O&M costs associated with this Program. The table below sets out the estimated number of Projects and estimated annual costs for this Program for 2020-2022.

	Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2020	21	$5.6
2021	35	$15.2
2022	28	$15.0

Substation Extreme Weather Hardening

Q. Please provide a description of the Substation Extreme Weather Hardening Program?

A. The primary objective of this Program is to harden and protect the company’s substation assets that are vulnerable to flood or storm surge. This Program will minimize outages, reduce restoration times and enhance emergency response during extreme weather events. The company has identified 59 of its 216 substations that have some level of risk to flood or surge. 1898 modeled these 59 substations and prioritized based on the expected benefits of mitigation after hardening each with a flood wall solution. Utilizing this approach, 1898’s model selected 11 substation hardening projects for the SPP Plan. Surprisingly, 1898’s model indicated that the substation hardening projects account for a sizable restoration benefit while requiring a small percentage of the Plan’s capital investment. Given this dramatic benefit to cost ratio, the company decided that further evaluation and assessment of this Program is needed. The company plans to perform a study utilizing a third party consultant that specializes in substation hardening and asset management in 2021 to evaluate various substation hardening solutions and assess the potential vulnerability of the identified substations to extreme weather, including flooding or storm surge. The results of the study will include a recommendation for each substation to be hardened, including the most cost effective hardening solution identified for each and a cost-benefit analysis. The study is estimated to cost around $250,000 and will produce a list of prioritized substation hardening projects.

Q. Please explain how Tampa Electric’s Substation Extreme Weather Protection Program will enhance the utility’s existing transmission and distribution facilities?

A. This Program will increase the resiliency and reliability of the substations through measures such as permanent or temporary barriers, elevating substation equipment, or relocating facilities to areas that are less prone to flooding. For those substations that are located closest to the coastline and of greatest risk, substation hardening efforts will eliminate or mitigate the impact of water intrusion due to storm surge into the substation control houses and equipment. By avoiding these types of impacts, restoration costs will certainly be reduced as will outage times.

Q. Please explain how Tampa Electric prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Substation Extreme Weather Protection Program?

A. Yes. Installing either permanent/temporary barriers, elevating substation equipment, or relocating facilities to areas that are less prone to flooding, will reduce restoration costs and times, as substation control houses and equipment would not exposed to major saltwater intrusion due to storm surge and/or flooding. If hardening efforts are not implemented, it would take Substation personnel or contractors an extremely long amount of time to flush equipment with clean water and air dry the equipment. Each piece of equipment would then need to be tested before it is placed back into service. All of these efforts will lead to significantly higher restoration costs and longer outage times. 1898’s model was utilized to estimate the benefits in reduced restoration costs and outage times as previously explained.

Q. Did Tampa Electric prepare a list of Substation Extreme Weather Protection Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

A. The company does not propose any substation projects for 2020.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

A. The company has not proposed any projects in 2020 but has identified 11 substations that have the greatest risk of impact due to flood or surge by an extreme weather event based on the preliminary analysis. The planned study will further refine this list and produce a project list and implementation plan.

Q. Would you explain in detail the methodology Tampa Electric used in prioritizing the projects the company is including in this Program?

A. The detailed engineering study the company plans to conduct will produce a list of recommendations including a prioritized list of substations to harden and the methodology utilized.

Q. Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

A. The company estimates that the study will cost around $250,000. The planned study will produce a project list with project cost estimates and the implementation plan.

Q. Did Tampa Electric prepare an estimate of benefits (reduction in outage time, reduction in extreme weather restoration cost) for the projects the company is planning on initiating for this Substation Extreme Weather Hardening Program?

A. The company has not proposed any projects in 2020, however, the planned engineering study will provide a list of projects and an estimate of costs and benefits for each proposed substation hardening project.

Q. Did Tampa Electric prepare a comparison of the estimated costs and benefits of the Program?

A. The scope of the planned engineering study will include a recommended list of proposed hardening projects and a comparison of the estimated costs and benefits of the Program.

Distribution Overhead Feeder Hardening

Q. Please provide a description of the Distribution Overhead Feeder Hardening Program?

A. Tampa Electric's distribution system includes feeders, also referred to as mainline or backbone, and laterals, which are tap lines off the main feeder line. The feeder is the main line that originates from the substation and is the most critical to ensuring power is reliably delivered to our customers one it leaves the substation. While the company has hardened some of its feeders that serve critical customers, this SPP Program will expand that effort to include some of our highest priority feeders, starting with those that have the worst historical day-to-day performance and performance during major storm events, those with the highest likelihood of failure, and those that would present the greatest impact if an outage were to occur.

Q. How will this Program harden the company’s feeders?

A. The Distribution Overhead Feeder Hardening Program includes strategies to further enhance the resiliency and reliability of the distribution network by further hardening the grid to minimize interruptions and reduce customer outage counts during extreme weather events and abnormal system conditions. These include stronger/hardened poles and facilities, installation of switching equipment to allow for automatic isolation of damaged facilities, upgrading of small wire conductor to ensure automatic service restoration is not limited by capacity constraints and the use of new equipment to minimize the interruption of service during atypical system configurations.

Q. What switching equipment does the company plan to install as a part of this Program?

A. The company will install reclosers and trip savers to minimize the number of customers interrupted during events as well as reduce the outage time for customers. This equipment will allow for the automatic isolation of faults on the system and then ultimately allow the network to re-configure itself real-time without operator intervention.

Q. How does the company plan to harden poles on feeder lines?

A. Hardening these feeders will include upgrading the poles older than 35 years of age, smaller than class 2 and ensuring the feeders meet NESC extreme wind loading standards along the feeder to increase the overall resiliency of the feeder. As an example, concrete poles that have a higher wind loading capacity may be utilized at key locations on the feeder such as switch, recloser, 3-phase transformer bank and capacitor bank locations. Additional steps that will be taken to harden the feeders and reduce restoration times will be installing sectionalizing switching devices, fault current sensors/indicators, and creating circuit ties to allow for automation.

Q. Please explain how Tampa Electric’s Distribution Overhead Feeder Hardening Program will enhance the utility’s existing transmission and distribution facilities?

A. The Distribution Overhead Feeder Hardening Program will enhance the resiliency of the distribution system by increasing the strength of the poles at most risk of failing during a major weather event as well as the poles at key locations along the feeder that would cause the greatest impact if a failure occurred. Tampa Electric has approximately 800 distribution feeders that serve near 1,000 customers on average each so mitigating the potential of an outage on these feeders is critical to minimizing customer outages. In addition, the company plans to add fault detection, isolation and restoration devices on feeders, which will significantly reduce the number of customers experiencing an outage during an event and allow those that do to be restored significantly quicker.

Q. Did Tampa Electric prepare a list of Distribution Overhead Feeder Hardening Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

A. Yes, the list of Distribution Overhead Feeder Hardening Projects for 2020 and their associated starting and projected completion dates is included in Appendix D of the

Plan and in my Exhibit No. RBH-1, Document No. 4. The company has a very preliminary list of Projects for 2021 and has identified how many distribution feeders the company plans to harden in the years 2022-2029.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

A. Yes, included in Appendix D of the Plan and in my Exhibit No. RBH-1, Document No. 4, the description of facilities affected include a unique Project identifier, the number and type of major equipment upgraded or installed, and the number and type of customers served by the facilities.

Q. Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

A. Yes. The company has developed cost estimates for each Project within this Program for 2020 and 2021 and totaled those estimates to derive the annual cost estimates for the Program. The company first defined the attributes of a hardened feeder and then applied the new criteria to each potential overhead feeder to develop its cost estimate to harden. The estimated costs for each Project reflect bringing that feeder up to the new hardened standard which includes poles meeting NESC Extreme Wind loading criteria, no poles lower than a class 2, no conductor size smaller than 336 ACSR, single phase reclosers or trip savers on laterals, feeder segmented and automated with no more than 200-400 customers per section and no segment longer than 2-3 miles, no more than two to three MWs of load served on each segment, and circuit ties to other feeders with available switching capacity. The company then estimated the number of Projects it expects to complete in years 2022-2029 with average Project cost estimates to develop the annual Program costs in those years. The estimated costs for this Program include $6.5M in 2020, $15.4M in 2021, 29.6M in 2022, and then approximately $33M in each year 2023-2029. There were no incremental O&M costs associated with this Program. The table below includes the estimated number of Projects and estimated costs per year for 2020-2022.

	Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2020	5	$6.5
2021	18	$15.4
2022	13	$29.6

Infrastructure Inspections

Q. Please provide a description of the Infrastructure Inspections Program?

A. Thorough inspections of Tampa Electric’s poles, structures and substations is critical for ensuring the system is maintained and in a resilient state should the company experience a major storm event. This SPP Program involves the inspections performed on the company’s T&D infrastructure including all wooden distribution and transmission poles, transmission structures and transmission substations, as well as the audit of all joint use attachments.

Q. Does Tampa Electric currently carry out infrastructure inspections?

A. Yes. Tampa Electric's Infrastructure Inspection Program is part of a comprehensive program initiated by the Florida Public Service Commission for Florida investor-owned electric utilities to harden the electric system against severe weather and to identify unauthorized and unnoticed non-electric pole attachments which affect the loadings on poles. This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No.

20060078-EI which requires each investor-owned electric utility to implement an inspection program of its wooden transmission, distribution and lighting poles on an eight-year cycle based on the requirements of the NESC. This Program provides a systematic identification of poles that require repair or replacement to meet strength requirements of NESC. Tampa Electric performs inspections of all wood poles on an eight-year cycle. Tampa Electric has approximately 290,000 wooden distribution and lighting poles and 25,700 transmission poles and structures that are part of an inspection program. Approximately 12.5 percent of the known pole population will be targeted for inspections annually although the actual number of poles may vary from year to year due to recently constructed circuits, de-energized circuits, reconfigured circuits, etc.

Q. How will the Infrastructure Inspection Program identify potential system issues?

A. The Tampa Electric Transmission System Inspection Program identifies potential system issues along the entire transmission circuit by analyzing the structural conditions at the ground line and above ground as well as the conductor spans. Formal inspection activities included in the Program are ground line inspection, ground patrol, aerial infrared patrol, above ground inspection and transmission substation inspections. Typically, the ground patrol, aerial infrared patrol and substation inspections are performed every year while the above ground inspections and the ground line inspection are performed on an eight-year cycle.

The company also performs joint use audits and inspections to mitigate the impact unknown foreign attachments could create by placing additional loading on a facility. All Tampa Electric joint use agreements have provisions that allow for periodic inspections and/or audits of all joint use attachments to the company's facilities to be paid for by the attaching entities.

Q. Please explain how Tampa Electric's Infrastructure Inspections Program will enhance the utility's existing transmission and distribution facilities?

A. Timely inspections and identification of required maintenance items can greatly reduce the impact of major storm events to the transmission and distribution system. Given that poles are critical to the integrity of the transmission and distribution grid, pole inspections are a key component of this SPP Program. Pole failures during a major storm event can cause a significant impact since there is high probability that the equipment attached to the pole will also experience damage. Cascading failures of other poles will also likely occur. Specifically, wood poles pose the greatest risk of failure and must be maintained and eventually replaced given they are prone to deterioration. The 8-year wood pole inspection requirement put in place by the Florida Public Service Commission is aimed at identifying any problems with a pole so they can be mitigated before they cause a problem during a major storm event. In addition, the other FPSC required inspections included in this SPP Program are also aimed at identifying compromised equipment that may create a vulnerability so that they can be addressed prior to causing a problem during a major storm event.

Q. Please explain how Tampa Electric prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Infrastructure Inspections Program?

A. While Tampa Electric did not prepare estimates of the reduction in outage times and restoration costs for this Program, as I previously discussed, inspections play a critical role in identifying issues with infrastructure and facilities so appropriate repairs can be made before a failure and resulting outage occurs. By doing so, the number of outages and outage times, not only during a major storm event, but also during day-to-day operations will be significantly reduced. In addition, planned repairs of equipment and facilities identified through an inspection are significantly less costly than restoring after a failure or following a major storm event.

Q. Did Tampa Electric prepare a list of Infrastructure Inspections Projects that the company is planning on initiating in 2020, including their associated starting and projected completion dates?

A. Tampa Electric conducts thousands of inspections each year so rather than identify various projects, the company has identified the number of inspections by type planned for 2020 – 2022 along with the estimated spend. The table included below sets out this information. Typically, these inspections are conducted throughout the year and have no specific start and completion date except for the bulk electric transmission and critical 69kV transmission substation and line inspections which are inspected first and prior to the peak of hurricane season each year.

Projected Number of Infrastructure Inspections			
	2020	2021	2022
Joint Use Audit	Note 1		
Distribution			
Wood Pole Inspections	22,500	22,500	35,625
Groundline Inspections	13,275	13,275	21,018
Transmission			
Wood Pole/Groundline Inspections	702	367	707
Above Ground Inspections	2,949	3,895	3,396
Aerial Infrared Patrols	Annually	Annually	Annually
Ground Patrols	Annually	Annually	Annually
Substation Inspections	Annually	Annually	Annually

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each Project including the number and type of customer(s) served?

A. As previously mentioned, Tampa Electric conducts thousands of inspections each year and has not identified specific projects or affected facilities. The company has identified the number of inspections by type planned for 2020 – 2022. While all customers will certainly benefit from this SPP Program, it is not practical to list specific customers or type of customers benefiting from a particular inspection.

Q. Would you explain in detail the methodology Tampa Electric used in prioritizing inspections?

A. Tampa Electric typically prioritizes its inspections by age or date of last inspection. Other criteria used to prioritize when inspections are performed include; bulk electric transmission and critical 69kV transmission substations and lines are inspected first and prior to the peak of hurricane season each year, circuits are patrolled based on their criticality or priority ranking, and finally, aerial infrared scans are scheduled in the summer time when load is highest which improves the accuracy of the results.

Q. Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

A. Yes. This can be located in the table below. The estimated costs for this Program include $1.2M in 2020, $1.5M in 2021 and then approximately $1.5M in each year 2022-2029. All costs associated with this Program are O&M.

Projected Costs of Infrastructure Inspections (in thousands)			
	2020	**2021**	**2022**
Distribution			
Wood Pole/Groundline Inspections	$708	$1,000	$1,020
Transmission			
Wood Pole/Groundline Inspections	$60	$61	$62
Above Ground Inspections	$10	$10	$10
Aerial Infrared Patrols	$110	$112	$114
Ground Patrols	$145	$148	$151
Substation Inspections	$140	$143	$146

Q. Did Tampa Electric prepare a comparison of the estimated costs and benefits of the Program?

A. Yes. The company has provided the costs associated with this Program and a description of the benefits provided.

Legacy Storm Hardening Initiatives

Q. Please provide a description of the Legacy Storm Hardening Initiatives?

A. The company plans to continue several well-established in place Storm Hardening Plan activities, referred to here as

Legacy Storm Hardening Plan Initiatives. Tampa Electric believes these Initiatives will continue to offer the storm resiliency benefits previously identified by the Commission. These Initiatives include a Geographical Information System, Post-Storm Data Collection, Outage Data - Overhead and Underground Systems, Increase Coordination with Local Governments, Collaborative Research, Disaster Preparedness and Recovery Plan and Distribution Pole Replacements.

Tampa Electric's Geographic Information System ("GIS") will continue to serve as the foundational database for all transmission, substation and distribution facilities. Regarding Post-Storm Data Collection, Tampa Electric has a formal process in place to randomly sample and collect system damage information following a major weather event. Tampa Electric has a Distribution Outage Database that it uses to track and store overhead and underground system outage data. Tampa Electric has an Emergency Preparedness team and representatives that will continue to focus on maintaining existing vital governmental contacts and participating on committees to collaborate in disaster recovery planning, protection, response, recovery and mitigation efforts. Tampa Electric will also continue to participate in the collaborative research effort with

Florida's other investor-owned electric utilities, several municipals and cooperatives to further the development of storm resilient electric utility infrastructure and technologies to reduce storm restoration costs and customer outage times. Tampa Electric will continue to maintain and improve its Disaster Preparedness and Emergency Response Plans and be active in many ongoing activities to support the improved restoration of the system before, during and after storm activation. Tampa Electric's distribution pole replacement initiative starts with the company's distribution wood pole and groundline inspections and includes restoring, replacing and/or upgrading those distribution facilities identified to meet or exceed the company's current storm hardening design and construction standards.

Q. Please explain how Tampa Electric's Legacy Storm Hardening Plan Initiatives will enhance the utility's existing transmission and distribution facilities?

A. As I've mentioned, all of these initiatives are well-established and have been in place since the Commission determined that they should be implemented and would provide benefits by enhancing the transmission and distribution system, reducing restoration costs and/or customer outage times.

Q. Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

A. Yes. In the table below, the company summarizes the expected capital and operating expenses for these initiatives during the 2020-2022 period. Tampa Electric plans to invest $9.42M in 2020, $11.18M in 2021 and $14.72M in 2022 of capital for distribution pole replacements. There is an associated operating expense of $520k in 2020, $620k in 2021 and $810k in 2022 for this activity. In addition, the company plans to incur $300k per year 2020-2022 in operating expenses for Disaster Preparedness and Emergency Response activities.

	Tampa Electric's Legacy Storm Hardening Plan Initiatives Projected Costs(in millions)	
	Disaster Preparedness and Recovery Plan	Distribution Pole Replacements
2020	$0.3	$9.9
2021	$0.3	$11.8
2022	$0.3	$15.5

ADHERENCE TO F.A.C. RULES AND STATUTORY REQUIREMENTS

Q. Does Tampa Electric's 2020-2029 Storm Protection Plan include all of the Program-level detail required by Rule 25-6.030(3)(d) and the Project-level detail required by Rule 25-6.030(3)(e)?

A. Yes. The Plan includes all the required Program-level detail for the six Storm Protection Programs described in my testimony. The Plan also includes the necessary Project-level detail for the Programs that contain Storm Protection Projects.

CONCLUSIONS

Q. Please summarize your direct testimony.

A. My testimony demonstrates that the six Programs I've discussed in Tampa Electric's proposed 2020-2029 Storm Protection Plan are consistent with Rule 25-6.030(3)(d)-(e), F.A.C. My testimony also demonstrates that these Programs will reduce restoration costs and outage times and enhance reliability in a cost-effective manner.

Q. Should Tampa Electric's proposed Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder

Hardening, Infrastructure Inspections, and Legacy Storm Hardening Programs be approved?

A. Yes. These Programs should be approved. These Programs meet the requirements of Rule 25-6.030 and they are designed to strengthen the company’s infrastructure to withstand extreme weather conditions, reduce restoration costs, reduce outage times, improve overall reliability and increase customer satisfaction in a cost-effective manner.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of John H. Webster was inserted.)

INTRODUCTION:

Q. Please state your name, address, occupation and employer.

A. My name is John H. Webster. My business address is 2200 East Sligh Av, Tampa, Florida 33610. I am employed by Tampa Electric Company ("Tampa Electric" or "the Company") as the Line Clearance Arborist Lead, Line Clearance and Construction Services, Energy Delivery Department.

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

A. My duties and responsibilities include ensuring safe, efficient, and cost-effective methods are in place for all line clearance activities associated with the construction and maintenance of Tampa Electric's transmission and distribution systems. This includes responsibility for line clearance contracted personnel, assigned budgets, equipment, and implementation of proper line clearance methodology. As it relates to this filing, I am responsible for the safe, timely, and efficient implementation of the company's Vegetation Management Program and Transmission Access Program.

Q. Please describe your educational background and professional experience?

A. I received a Bachelor of Science degree in forestry from the University of Kentucky in 2003 and became an International Society of Arboriculture certified arborist in 2003 and an International Society of Arboriculture certified utility specialist in 2004. I have been with Tampa Electric for fourteen years, and held positions as a Line Clearance Supervisor, Line Clearance Arborist, and Line Clearance Arborist Lead.

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

A. The purpose of my direct testimony is to present the Vegetation Management and Transmission Access Storm Protection Programs in Tampa Electric's 2020-2029 Storm Protection Plan. My testimony will explain how the company's Vegetation Management Program complies with Rule 25-6.030(3)(f), and how the Transmission Access Program complies with Rule 25-6.030(3)(d)-(e). I will provide a description of the proposed Vegetation Management ("VM") Program and the Transmission Access Program. I will explain in detail the systematic approach the company used to develop the Vegetation

Management Program and the Transmission Access Program to ensure the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability are achieved.

Q. Are you sponsoring any exhibits in this proceeding?

A. No.

TAMPA ELECTRIC'S SERVICE AREA

Q. How many circuit miles of overhead distribution and transmission lines does Tampa Electric have?

A. The company has approximately 6,250 circuit miles of overhead distribution facilities and 1,350 circuit miles of overhead transmission facilities over the five counties Tampa Electric serves.

Q. Are there any parts of Tampa Electric's service area that were prioritized for enhancement, or any areas where enhancement would not be feasible, reasonable or practical, under the Vegetation Management and Transmission Access Programs?

A. No. The company did not exclude any area of the company’s existing transmission and distribution facilities for enhancement under these programs due to feasibility, reasonableness, or practicality.

TAMPA ELECTRIC’S CURRENT VEGETATION MANAGEMENT PROGRAM

Q. What are the components of the proposed Vegetation Management Program in the company’s SPP?

A. The company’s VM Program consists of four parts including existing legacy storm hardening VM activities and three new VM initiatives. The company’s existing VM activities and the three new VM initiatives are described below.

Q. Please explain Tampa Electric’s current distribution and transmission vegetation management cycles.

A. Tampa Electric’s current Vegetation Management Program (“VMP”) calls for trimming the company’s distribution system on a four-year cycle. The company’s bulk transmission lines of 138kV and 230kV are maintained on a two-year cycle and 69kV lines are maintained on a three-year cycle.

Q. When did Tampa Electric begin a four-year trim cycle for its distribution system?

A. The company received approval from the Commission in Docket No. 20120038-EI, Order No. PSC 12-0303-PAA-EI, issued June 12, 2012 to convert from a three-year trim cycle to a four-year trim cycle. This approved trim cycle change gave Tampa Electric flexibility to change circuit prioritization using the company's reliability-based methodology.

Q. Approximately how many miles of distribution lines does Tampa Electric trim per year as part of this four-year cycle?

A. Tampa Electric’s current four-year trim cycle calls for trimming approximately 1,560 distribution miles annually.

Q. Describe Tampa Electric’s transmission VM cycle.

A. As I mentioned previously, the company’s bulk transmission lines of 138kV and 230kV are maintained on a two-year cycle and 69kV lines are maintained on a three-year cycle. Transmission circuits are managed on a ‘strict’ or ‘hard’ cycle. Although strict, the schedule allows adequate flexibility to accommodate new or redesigned circuits. All circuits above 200kV are managed in accordance with Federal Energy Regulatory Commission ("FERC") standard FAC-003-4.

Q. Approximately how many miles of transmission lines does Tampa Electric trim per year as a part of these cycles?

A. Tampa Electric's current transmission cycle calls for trimming approximately 530 total transmission miles annually, 255 non-bulk miles and 275 bulk miles.

Q. Would you explain the company's reliability-based methodology?

A. Tampa Electric's System Reliability and Line Clearance Departments use a third-party vegetation management software application to develop a multi-year VMP which optimizes activities from both a reliability-based and cost-effectiveness standpoint. This approach allows the company to model circuit behavior and schedule trimming at the optimal time.

Q. Please describe the company's current VM specifications.

A. Tampa Electric uses a contract workforce of approximately 220 tree trim personnel throughout the company's distribution and transmission system. Vegetation to conductor clearance for distribution primary facilities is ten feet, and vegetation to conductor clearances for transmission varies from fifteen feet to thirty feet, depending on voltage. All Tampa Electric contractors are required to follow American National Standards Institute ("ANSI") A300 pruning guidelines.

Q. What are ANSI pruning guidelines?

A. The American National Standards Institute or ANSI uses industry research to generate a set of guidelines for a variety of industry practices. The ANSI A-300 guidelines help arborists determine the manner in which vegetation should be trimmed to achieve desired objectives all while preserving tree health and structure. The Z-133 guidelines help arborists and non-arborists follow safe work practices.

Incremental Vegetation Management Initiatives

Q. In his direct testimony, Gerard R. Chasse mentions that Tampa Electric used a consultant to analyze potential incremental vegetation management activities. Please explain why Tampa Electric used this consultant.

A. The company used Accenture for its industry knowledge and data analysis expertise. Additionally, Accenture has worked with Tampa Electric on a number of VM analyses in the past, owns the software application, and has a working knowledge of the company's VM processes.

Q. How did Accenture analyze Tampa Electric's existing VM activities?

A. Accenture analyzed Tampa Electric's historical reliability and VM data and incorporated (FEMA HAZUS) wind speed and storm probability data to model the costs and benefits of various VM activities. Accenture collected thirteen years of reliability and VM data. The reliability data included outages related to vegetation as well as a percentage of other outages that may have a vegetation component such as weather cause codes and unknown cause codes. The VM data included circuit-specific trim dates and costs. The VM software application was the primary tool for analysis.

Q. How does Accenture's VM software application work?

A. The VM software application uses multi-year outage data and pairs it with multi-year VM activity and cost to generate reliability and cost 'curves.' These curves model circuit behavior and recommend the optimal time for VM. The application also has a corrective trimming and storm function that allows it to estimate costs associated with corrective or mid-cycle trimming and storm restoration.

Q. Did Accenture update the tree trimming model for this study?

A. Yes. Tampa Electric worked with Accenture to update the software application with the company's most recent outage and cost data. Accenture further updated the application by creating an enhanced storm module to accompany the existing storm module already in the application. The enhanced storm module allowed the application to perform analyses on partial circuits and entire circuits.

Q. Did Accenture analyze multiple scenarios involving potential incremental VM activities?

A. Yes, Accenture looked at multiple mileage scenarios to determine the costs of incremental VM activities and the benefits associated with extreme weather events and overall service reliability. Accenture modeled seven scenarios ranging from zero incremental VM miles to nine-hundred incremental VM miles. The addition of the enhanced storm module allowed Accenture to analyze the costs and benefits of two mid-cycle VM scenarios.

Q. What were Accenture's conclusions?

A. Accenture concluded a supplemental VM initiative consisting of seven hundred incremental miles would provide a twenty-one percent improvement in the company's storm restoration times and costs. Based on Accenture's work, the proposed mid-cycle VM initiative, consisting of four-hundred forty incremental miles inspected, would net an additional five percent improvement in the company's storm restoration times and costs.

Q. Did Accenture determine which combination of incremental activities provided the greatest level of benefit for the cost?

A. Yes. Accenture determined which combination of incremental activities provided the greatest benefit through the analysis and worked closely with company subject-matter experts to produce an operational plan that incorporates efficient, cost-effective contractor uptake. The result was a phased-in approach of four-hundred, five-hundred, seven-hundred miles scheduled for the first three years of the Storm Protection Plan.

Q. Did Accenture analyze potential incremental transmission VM activities?

A. No, Accenture did not analyze the incremental transmission activities primarily because the VM software application is designed for distribution circuits. Additionally, much of the company's transmission VM plan is regulated by FERC standard FAC-003-4.

Q. Did Tampa Electric determine that it should perform any incremental transmission vegetation management?

A. Yes, the company assessed its transmission circuits and found through operational experience and storm "lessons learned" that approximately ten percent of the 69kV transmission miles were particularly difficult and expensive to maintain, largely inaccessible, and prone to hazard trees. The company's proposed 69kV reclamation project would essentially remove the vegetative obstructions and minimize outages related to hazard tree fall-ins.

Q. Can you please describe each of the incremental VM activities, both for transmission and distribution, that Tampa Electric proposes as elements of its 2020-2029 Storm Protection Plan?

A. In addition to its existing VM activities, Tampa Electric is proposing three initiatives (two distribution and one transmission) designed to further harden the company's electrical infrastructure against extreme weather events and improve overall system reliability. They are the Supplemental Distribution Circuit VM Initiative, the Mid-Cycle Distribution VM Initiative and 69 kV Transmission VM Reclamation Initiative.

The Supplemental Distribution Circuit VM Initiative will increase the volume of full circuit VM performed on an annual basis. The Mid-cycle Distribution VM Initiative is an inspection-driven, site-specific approach designed to target vegetation that cannot be effectively maintained by cycle trimming. This initiative will also target hazard trees. The 69 kV Transmission VM

Reclamation Initiative is designed to remove obstructing vegetation and hazard trees from specific sites along the company's 69 kV transmission system.

Q. Please explain how Tampa Electric's Incremental Vegetation Management Initiatives will enhance the utility's existing transmission and distribution facilities?

A. The Supplemental Distribution Circuit VM Initiative, once fully implemented, is expected to provide a sixteen percent and twenty-one percent improvement in the company's day-to-day and storm restoration times and costs, respectively. The Mid-Cycle Distribution VM Initiative is expected to net an additional two percent and five percent improvement in the company's day-to-day and storm restoration times and costs, respectively. The hazard tree removal portion of the initiative will add further benefit to storm outage prevention. The 69 kV Transmission VM Reclamation Initiative will benefit storm outage prevention by improving vegetation to conductor clearance and reducing hazard tree potential. During extreme weather events, these initiatives will have added benefit for faster outage detection, more accurate damage assessment, and lower restoration times and costs.

Q. How many incremental miles of distribution and transmission overhead facilities does Tampa Electric plan to trim over the first three years of the Plan?

A. For the first three years, the company plans to trim approximately 1,600 additional miles of distribution lines and an additional 56 miles of 69 kV transmission lines. The number of miles of mid-cycle trimming and removal will be determined by the inspection findings; however, the company plans to inspect 439 miles in the first three years of the SPP.

Q. What is the total number of miles, including both baseline and incremental trimming, that Tampa Electric plans to trim over the first three years of the Plan?

A. The company plans to trim approximately 4,680 miles of distribution facilities under the baseline cycle and 1,600 miles under the Supplemental Trimming Initiative for a total of approximately 6,280 miles of distribution trimming. The company also plans to inspect an additional 439 miles of distribution facilities under the Mid-Cycle Initiative. The company plans to trim approximately 1,590 miles of transmission facilities under the baseline cycle, plus an additional 83 miles under the 69kV Reclamation Initiative, for a total of approximately 1,673 miles of transmission facility trimming.

Q. What are the estimated annual labor and equipment costs for the VM Program during the first three years of the SPP?

A. The estimated annual labor and equipment costs for the first three years of the SPP total $67.2M, commencing second quarter of 2020. The four-year distribution cycle labor and equipment costs for the first three years are $36.8M, and the incremental distribution VM labor and equipment costs are $20.6M. The first three years of transmission cycle(s) labor and equipment costs are $8.3M, and the incremental transmission VM labor and equipment costs are $1.5M. The total cost for the Program is set out in Section 7 of the company's 2020-2029 SPP.

Q. Did Tampa Electric prepare an analysis of the estimated costs and benefits of the Program?

A. Yes, pursuant to Rule 25-6.030(3)(i), the company explored incremental VM strategies for the express purposes of protecting its electrical infrastructure against extreme weather events and reducing restoration times and costs. The company further acquired the assistance of Accenture, an outside consultant with expertise in data analysis and utility VM, to help with the analysis. Based on the data available and the analysis performed, Tampa Electric believes that the twenty-six percent improvement in storm restoration time and cost are worth the $10.7M annual average increase in distribution VM operations and maintenance expenses. The benefits associated with reduced restoration time and cost and lessened vegetation contact potential also clearly show that the $2.2M 69kV reclamation project additional annual expense is a tremendous value for Tampa Electric customers.

TRANSMISSION ACCESS PROGRAM

Q. Please describe the Transmission Access Program?

A. Tampa Electric’s Transmission Access Program is designed to ensure the company always has access to its transmission facilities so it can promptly restore its transmission system when outages occur. Increased power demands and changes in topography and hydrology related to customer development, along with several years of active storm seasons, have negatively impacted the company's access to its transmission infrastructure. The company's proposed Transmission Access Program involves repairing and restoring transmission access by constructing access roads and access bridges to critical routes throughout the company's transmission corridors. The program is expected to start projects in 2021 and complete the program by 2030.

Q. Please explain how Tampa Electric's Transmission Access Program will enhance the utility's existing transmission facilities.

A. This program will enhance the existing transmission facilities by improving the company's access to its critical transmission circuits, especially during 'wet' and storm seasons, which will promote system resiliency and timelier storm restoration.

Q. In the direct testimony of Gerard R. Chasse, he mentions that Tampa Electric used a consultant to assist with the development of the Transmission Access Program. Please explain why Tampa Electric used a consultant to develop the Transmission Access Program.

A. Tampa Electric hired 1898 & Co, a consultant with expertise in the areas of T&D system hardening and cost-benefit analysis. 1898 was selected for its industry knowledge and data analysis expertise. 1898 & Co. was engaged to analyze the cost-benefits of the access projects for prioritization within the Program as well as the overall Plan. Jason D. De Stigter from 1898 will provide direct testimony to more fully detail the approach taken for each of the Programs they supported, including Transmission Access.

Q. Please explain how Tampa Electric and 1898 & Co. prepared the estimate of the reduction in outage times and restoration costs due to extreme weather conditions that will result from the Transmission Access Program?

A. The methodology used to develop the estimate of the reduction in outage times and restoration costs is addressed in detail in Jason D. De Stigter’s direct testimony, but in general, 1898 developed a model that calculates the benefit in terms of decreased restoration cost and reduced Customer Minutes of Interruption (“CMI”) for each proposed Transmission Access Project.

Q. Did Tampa Electric prepare an analysis of the estimated costs and benefits of the Transmission Access Program?

A. Yes. A table comparing the estimated costs and benefits of this Program is included below.

Tampa Electric - Proposed 2020-2029 Storm Protection Plan Transmission Access Enhancements Program Projected Costs versus Benefits						
Storm Protection Program	**Projected Costs (in Millions)**		**Projected Reduction in Restoration Costs (Approximate Benefits in Percent)**	**Projected Reduction in Customer Minutes of Interruption (Approximate Benefits in Percent)**	**Program Start Date**	**Program End Date**
	Capital	**O&M**				
Transmission Access Enhancements	$14.8	$0.0	10	74	Q1 2021	After 2029

Q. Please explain the methodology Tampa Electric used in prioritizing the Projects the company is including in the Transmission Access Program.

A. The methodology used to develop the prioritization of Projects in these Programs is addressed in detail in Jason D. De Stigter's direct testimony. In general, the company and 1898 developed a potential cost estimate and estimated benefits for each potential Project in the Program. These estimated benefits included both reduced customer minutes of interruption and reduced restoration costs. These benefits were then combined and a cost benefit NPV was calculated for each potential Project. The NPVs were then used to rank or prioritize each Project within a given SPP Program. The rankings will serve as a guide, but the company will also apply operational experience and judgment when selecting Projects.

Q. Did Tampa Electric prepare a list of transmission access projects that the company is planning to begin in 2020, including their associated starting and projected completion dates?

A. No, the company did not prepare a list of Transmission Access Projects for 2020. Tampa Electric plans to use 2020 to select engineering and construction vendors and coordinate the necessary environmental permitting.

Q. Did Tampa Electric prepare an estimated number of Transmission Access projects it plans on initiating in 2021 and 2022?

A. Yes, using the analysis provided by 1898, the company prioritized a list of fourteen Projects it plans to begin in 2021 and 2022.

Q. Did Tampa Electric prepare an estimate of the costs for the projects planned for 2021 and 2022?

A. Yes, the company plans to spend $2.9M for Projects planned in 2021 and 2022. The table below sets out the total number of Projects and the estimated costs for the first three years of the Plan.

	Tampa Electric's Transmission Access Enhancements Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2020	0	$0.0
2021	8	$1.4
2022	6	$1.5

Q. Did Tampa Electric prepare a cost estimate for this Program, including capital and operating expenses?

A. Yes, the company used recent road and bridge actuals to prepare estimates for the permitting, surveying, engineering, and construction costs. The total capital cost estimate for the Transmission Access Enhancement Program is $14.8M. The are no operating costs associated with the Projects. The table below sets out the estimated costs for the Program by year over the ten-year plan horizon.

	Total Transmission Access Enhancements Program Costs (in thousands)		
	Access Road Projects Costs	**Access Bridge Project Costs**	**Total Transmission Access Project Costs**
2020	$0	$0	$0
2021	$604	$780	$1,383
2022	$391	$1,118	$1,509
2023	$0	$1,606	$1,606
2024	$810	$853	$1,663
2025	$978	$360	$1,338
2026	$0	$354	$354
2027	$3,325	$0	$3,325
2028	$1,982	$0	$1,982
2029	$1,065	$601	$1,667

CONCLUSIONS:

Q. Please summarize your direct testimony.

A. My testimony and my accompanying exhibits present and support the Incremental Vegetation Management Program within Tampa Electric’s proposed 2020-2029 Storm Protection Plan. This Plan was developed consistent with the requirements of Section 366.96, Florida Statutes and the implementing Rule 25-6.030, F.A.C., adopted by the Commission.

Q. Should Tampa Electric’s proposed Vegetation Management and Transmission Access Programs be approved?

A. Yes. Tampa Electric’s proposed 2020-2029 Vegetation Management and Transmission Access Programs should be approved. These Programs are designed to reduce restoration costs, reduce outage times, improve overall reliability and increase customer satisfaction in a cost-efficient manner.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of A. Sloan Lewis was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200067-EI
FILED: APRIL 10, 2020

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

A. SLOAN LEWIS

INTRODUCTION:

Q. Please state your name, address, occupation and employer.

A. My name is A. Sloan Lewis. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the Company") in the Finance Department as Director, Regulatory Accounting.

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

A. My duties and responsibilities include the accounting oversight of all cost recovery clauses and riders for Tampa Electric and Peoples Gas, the settlement of all fuel and power transactions for Tampa Electric and Peoples Gas System and the accounts payable department for Tampa Electric, Peoples Gas System and New Mexico Gas Company.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in accounting from Florida State University in 1994 and a Master of Education from the University of North Florida in 1996. I joined Tampa Electric in 2000 as a Fuels Accountant and over the past 19 years have expanded my cost recovery clause responsibilities. Then in 2015, I was promoted to Manager, Regulatory Accounting with responsibilities for all the recovery clauses and riders for Tampa Electric and Peoples Gas System. I was promoted to my current role as Director, Regulatory Accounting in 2017.

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

A. The purpose of my testimony in this proceeding is to demonstrate that the company’s 2020-2029 Storm Protection Plan complies with Rule 25-6.030(g)-(h), Florida Administrative Code, *i.e.*, the Storm Protection Plan (“SPP”) rule. Section 3(g) requires a utility to provide an estimate of the annual jurisdictional revenue requirements for each year of its SPP. Section 3(h) requires a utility to provide an estimate of rate impacts for each of the first three years of the SPP for the utility’s typical residential, commercial, and industrial customers. My testimony also explains the methodology used to calculate these estimates.

Q. Have you prepared an exhibit to accompany your direct testimony?

A. Yes. Exhibit No. ASL-1, entitled "Tampa Electric's 2020-2029 SPP Total Revenue Requirements by Program" was prepared under my direction and supervision. This Exhibit shows the Annual Revenue Requirement for the company's 2020-2029 SPP Programs.

CALCULATION OF THE ESTIMATED ANNUAL JURISDICTIONAL REVENUE REQUIREMENTS FOR TAMPA ELECTRIC'S 2020-2029 STORM PROTECTION PLAN

Q. What is the estimated annual jurisdictional revenue requirements for each year of the company's proposed SPP?

A. The estimated annual jurisdictional revenue requirements for each year of the SPP are included in the table below. The revenue requirements of each SPP are set out in my Exhibit No. ASL-1.

Total SPP Revenue Requirement (2020-2029)

YEAR	Revenue Requirements
2020	$24,428,727
2021	$36,739,224
2022	$52,213,995
2023	$71,458,756
2024	$86,932,411
2025	$105,253,007
2026	$122,774,696
2027	$139,916,133
2028	$157,595,194
2029	$174,852,375

Q. How were the estimated annual jurisdictional revenue requirements for the proposed plan developed?

A. The estimated annual jurisdictional revenue requirements were developed with cost estimates for each of the SPP Programs plus depreciation and return on SPP assets, as outlined in Rule 25-6.031(6), F.A.C., the Storm Protection Plan Cost Recovery Clause ("SPPCRC") Rule.

Q. Do these revenue requirements include any costs that are currently recovered in base rates?

A. Yes. As described further below, the revenue requirement amounts shown above reflect all of the investments and expenses associated with the activities in the Plan without regard to whether some of those costs may currently be subject to recovery through the company's existing base rates and charges. For illustrative purposes, the company calculated the 2017 to 2019 three-year actual amounts of certain operations and maintenance expenses associated with its current Storm Hardening Plan to be approximately $12.9 million. Since these Storm Hardening Plan activities are proposed to be part of the company's SPP and are not "new" or "incremental" storm protection activities, this $12.9 million amount can be viewed as a reasonable proxy for the amount of Storm Protection Plan costs currently being recovered by the company through its base rates and charges. Of course, whether and the extent to which the investments and costs associated with the company's SPP will be recovered through the SPPCRC or continue to be recovered through base rates will be addressed in Docket No. 20200092-EI, the SPPCRC Docket.

Q. Do the estimated annual jurisdictional revenue requirements include the annual depreciation expense on SPP capital expenditures?

A. Yes. Rule 25-6.031 states that the annual depreciation expense is a cost that may be recovered through the SPPCRC. As a result, the estimated annual jurisdictional revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures, *i.e.*, those initiated after April 10, 2020, using the depreciation rates from Tampa Electric's most current Depreciation Study, approved in PSC-12-0175-PAA-EI.

Q. Was the depreciation savings on the retirement of assets removed from service during the SPP capital projects considered in the development of the revenue requirement?

A. Yes. In the development of the revenue requirements, depreciation expense from the SPP capital asset additions has been reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the SPP capital projects.

Q. Do the estimated annual jurisdictional revenue requirements include a return on the undepreciated balance of the SPP assets?

A. Yes. Rule 25-6.031 6(c) states that the utility may recover a return on the undepreciated balance of the asset costs through the SPPCRC. As a result, this return was included in the estimated annual jurisdictional revenue requirement. In accordance with the FPSC Order No. PSC-12-0425-PAA-EU, from the 2012 Stipulation and Settlement agreement, Tampa Electric calculated a return on the undepreciated balance of the asset costs at a weighted average cost of capital using the return on equity from the May 2019 Actual Surveillance Report.

Q. In the development of the estimated annual jurisdictional revenue requirements did the company consider SPP capital expenditures prior to the plan filing date in the depreciation and return on asset calculations?

A. No. Only capital expenditures for SPP Projects to be initiated after April 10, 2020 were included in the depreciation and return on asset calculations included in the estimated annual jurisdictional revenue requirements.

Q. In the calculation of the estimated annual jurisdictional revenue requirements did the company include Allowance for Funds Used During Construction ("AFUDC")?

A. No. Per Rule 25-6.0141, F.A.C, in order for projects to be eligible for AFUDC, they must involve “gross additions to plant in excess of 0.5 percent of the sum of the total balance in Account 101, Electric Plant in Service, and Account 106, Completed Construction not Classified, at the time the project commences and are expected to be completed in excess of one year after commencement of construction.” None of the projects proposed in Tampa Electric’s 2020-2029 SPP meet the criteria for AFUDC eligibility.

Q. Does Tampa Electric intend to seek recovery of the estimated SPP costs through the SPPCRC, in accordance with FAC rule 26-6.031?

A. Yes, Tampa Electric will be filing for cost recovery of the estimated SPP costs through the SPPCRC. However, as mentioned above, the extent to which the investments and costs associated with the company’s SPP will be recovered through the SPPCRC or continue to be recovered through base rates will be addressed in Docket No. 20200092-EI.

CALCULATION OF THE ESTIMATED RATE IMPACTS FOR YEARS 2020-2023 OF THE STORM PROTECTION PLAN

Q. Please provide an estimate of rate impacts for each of the first three years of the proposed SPP for typical Tampa Electric residential, commercial, and industrial customers.

A. Tampa Electric prepared estimated rate impacts of the SPP for 2020, 2021, 2022 and 2023. While there are not going to be any billed rate impacts during 2020, the 2020 costs have been calculated separately from the 2021 costs so the impact of each year on the 2021 rate impacts is clear. This is because the 2020 costs will be recovered at the same time as the 2021 costs through clause rates initiating in January 2021. The estimated rate impacts for each of the first three years of the proposed SPP for a typical residential, commercial, and industrial Tampa Electric customer are listed in the table below.

	Tampa Electric's Storm Protection Plan "Total Cost" Customer Bill Impacts (in percent)			
	Customer Class			
	Residential 1000 kWh	Residential 1250 kWh	Commercial 1 MW 60 percent Load Factor	Industrial 10 MW 60 percent Load Factor
2020	1.50	1.48	1.44	0.55
2021	2.22	2.21	2.14	0.84
2022	3.09	3.06	2.98	1.13
2023	4.12	4.07	3.95	1.46

Q. How were the estimated rate impacts for each of the first three years of the proposed SPP for a typical residential and commercial/industrial customer determined?

A. For each year, the Programs were itemized and identified as either substation, transmission, or distribution costs. Each of those functionalized costs was then allocated to rate class using the allocation factors for that function. The allocation factors were from the Tampa Electric 2013 Cost of Service Study prepared in Docket No. 20130040-EI, which was used for the company’s current (non-SoBRA) base rate design. Once the total SPP revenue requirement recovery allocation to the rate classes was derived, the rates were determined in the same manner. For Residential, the charge is a kWh charge. For both Commercial and Industrial, the charge is a kW charge. The charges are derived by dividing the rate class allocated SPP revenue requirements by the 2020 energy billing determinants (for residential) and by the 2020 demand billing determinants (for commercial and industrial). Those charges were then applied to the billing determinants associated with typical bills for each group to calculate the impact on those bills. This was done using a combination of 2020 and 2021 costs for the 2021 bills, and for each year 2022 and 2023 for those bills.

Q. When will the company file its petition for the establishment of the 2021 SPPCRC rates for Tampa Electric’s SPP’S costs?

A. The company plans to file the SPPCRC petition for 2021 rates on the schedule specified in applicable orders establishing procedure in Docket No. 20200092-EI.

Q. Will the rates established through the 2021 SPPCRC differ from those presented in the rate impact calculations in the SPP?

A. Yes. The rate impacts presented above reflect the “all-in” costs of the company’s SPP without regard to whether the costs are or will be recovered through the SPPCRC or through the company’s base rates and charges. The extent to which the investments and costs associated with the company’s SPP will be recovered through the SPPCRC or continue to be recovered through base rates will be addressed in Docket No. 20200092-EI.

In addition, when it makes its SPPCRC filing, the company will use more recent billing determinants based on the most current load forecast.

The company will also take steps to prevent double recovery of any costs through both base rates and the clause.

CONCLUSIONS

Q. Please summarize your direct testimony.

A. My testimony and exhibit demonstrate that Tampa Electric's estimated annual jurisdictional revenue requirements for each of the 10 years of the SPP and rate impacts for each of the first 3 years of the SPP for the utility's typical residential, commercial, and industrial customers comply with Rule 25-6.030(3)(g)-(h). These calculations were performed in accordance with the requirements of Section 366.96, Florida Statutes and the implementing Rule 25-6.030, F.A.C., adopted by the Commission.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Jason D. De Stigter was inserted.)

VERIFIED DIRECT TESTIMONY OF JASON D. DE STIGTER
ON BEHALF OF
TAMPA ELECTRIC COMPANY

1. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q2. By whom are you employed and in what capacity?

A2. I am employed by 1898 & Co., and lead the Capital Asset Planning team as part of our Utility Consulting Practice. 1898 & Co. was established as the consulting and technology consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of over 200 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made up of more than 7,000 engineers, architects, construction professionals, scientists, consultants and entrepreneurs with more than 40 offices across the country and throughout the world.

Q3. Briefly describe your educational background and certifications.

A3. I received a Bachelor of Science Degree in Engineering and a Bachelor's in Business Administration from Dordt University. I am also a registered Professional Engineer in the state of Kansas.

Q4. Please briefly describe your professional experience and duties at 1898 & Co.

A4. I am a professional engineer with 13 years of experience providing consulting services to electric utilities. I have extensive experience in asset management, capital planning and optimization, risk and resilience assessments and analysis, asset failure analysis, and business case development for utility clients. I have been involved in numerous studies modeling risk for utility industry clients. These studies have included risk and economic analysis engagements for several multibillion-dollar capital projects and large utility systems. In my role as a project manager I have worked on and overseen risk and resilience analysis consulting studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resilience analysis models. My primary responsibilities are business development and project delivery within the Utility Consulting Practice with a focus on developing risk and resilience based business cases for large capital projects/programs.

Prior to joining 1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch inside their Asset Management Practice performing similar studies to the effort performed for Tampa Electric Company ("TEC").

Q5. Have you previously testified before the Florida Public Service Commission or other state commissions?

A5. I have not testified before the Florida Public Service Commission. I provided written, rebuttal, and oral testimony on behalf of Indianapolis Power & Light before the Indiana Utility Regulatory Commission and have supported many other regulatory filings. I have also testified in front of the Alaska Senate Resources Committee.

Q6. What is the purpose of your direct testimony in this proceeding?

A6. The purpose of my testimony is to summarize the results and methodology used by 1898 & Co. to develop a Storm Resilience Model with the following objectives:

1. Calculate the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish overall investment level that maximizes customers benefit while not exceeding TEC technical execution constraints

Through my testimony I will describe the major elements of the Storm Resilience Model, which include a Major Storms Event Database, Storm Impact Model, Resilience Benefit Module, and Budget Optimization & Project Prioritization. Specifically, I will define resilience, review historical major storm event to impact TEC service territory, describe the datasets used in the Storm Impact Model and how they were used to model system impacts due to storms events, and explain how to understand the resilience benefit results. Throughout my testimony I will describe both how the assessment was performed and why it was performed as such. Finally, I will describe the calculations and results of the Storm Resilience Model.

Q7. Are you sponsoring any attachments in support of your testimony?

A7. Yes, I am sponsoring the 1898 & Co, Tampa Electric's Storm Protection Plan Resilience Benefits Report that is being included as Appendix F in Tampa Electric's 2020-2029 Storm Protection Plan.

Q8. Were your testimony and the attachment identified above prepared or assembled by you or under your direction or supervision?

A8. Yes.

Q9. Are you also submitting workpapers?

A9. No.

Q10. What was the extent of your involvement in the preparation of the Storm Protection Plan?

A10. I served as the 1898 & Co. project manager on the TEC Storm Protection Plan Assessments and Benefits Assessment. The evaluation utilized a Storm Resilience Model to calculate benefits. I worked directly with the TEC Team involved in the resilience-based planning approach. I was responsible for the overall project and was directly involved in the development of the Storm Resilience Model, the assessment and results, as well as being the main author of the report.

2. RESILIENCE-BASED PLANNING OVERVIEW

Q11. Which of the Storm Protection Plan programs are evaluated within the Storm Resilience Model?

A11. The Storm Resilience Model includes project benefits results, budget optimization, and project prioritization for the following Storm Protection Plan programs:

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening

- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

Q12. How is resilience defined?

A12. There are many definitions for resilience, I gravitate to the one used by the National Infrastructure Advisory Council (NIAC). Their definition of resilience is: "The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."

This definition can be broken down into four phases of resilience described below with applicable definitions for the grid:

- **Prepare (Before)**

  The grid is running normally but the system is preparing for potential disruptions.
- **Mitigate (Before)**

  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.

- **Respond (During)**

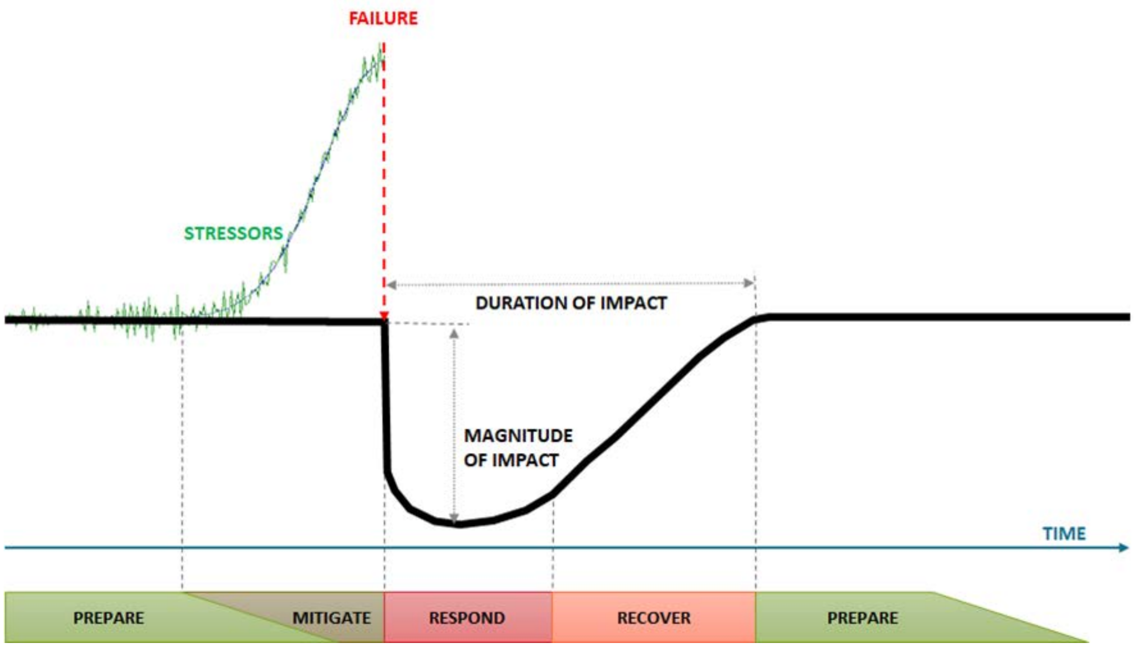
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).

- **Recover (After)**

  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

This is depicted graphically in Figure 1 below as a conceptual view of understanding resilience and how to mitigate the impact of events. The green line represents an underlying issue that is stressing the grid, and which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The black line shows the status of the entire system or parts of the system (e.g. transmission circuits). The "pit" depicted after the event occurs represents the impact on the system in terms of the magnitude of impact (vertical) and the duration (horizontal).

Figure 1: Phases of Resilience



Q13. How does the Storm Resilience Model incorporate this definition?

A13. The Storm Resilience Model utilizes a resilience-based planning approach to calculate hardening project benefits and prioritize projects. The model includes a 'universe' of major storm events as stressors on the TEC system. The database includes the probability of these events occurring as well as the magnitude of impact, in terms of the percentage of the sub-systems (e.g. substations, transmission lines, feeders, laterals), and duration to restore the system. The database also includes the restoration cost to return the system back to normal operation after each of the storm events.

The Storm Resilience Model also identifies, on a probability weighted basis, which specific portions of the TEC system would be impacted and their contribution to the overall restoration costs. The model also evaluates the storms impact for each portion of the system based on current status of the system and if that part of the system is hardened. For example, the Storm Resilience Model calculates magnitude and duration of a storm event on a distribution circuit given its current state and after it has been hardened.

Q14. Please outline the type and count of hardening projects evaluated in the Storm Resilience Model.

A14. Table 1 on the page below contains the list of potential hardening projects by program evaluated in the Storm Resilience Model.

Table 1: Potential Hardening Project Count

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

Q15. How were these potential hardening projects identified?

A15. The potential hardening projects were identified based on a combination of data driven assessments, field inspection of the system, and historical performance of TEC's system during major storm events. The approach to identifying hardening projects employs asset management principles utilizing a bottom-up approach starting with the system assets. Additionally, hardening approaches for parts of the system were based on the balance of the resilience benefit they provide with the overall costs. I discuss this more below. Table 2 on the page below shows the asset types and counts included in the Storm Resilience Model used to develop hardening projects.

Table 2: TEC Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	35,200
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	3,800
Steel / Concrete / Lattice Structures	[count]	17,700
Conductor	[miles]	1,300
Substations	**[count]**	**255**
Site Access	**[count]**	**96**
Roads	[count]	70
Bridges	[count]	26

All of the assets that benefit from hardening are strategically grouped into potential hardening projects. For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, a recloser, trip savers, or a fuse.

For lateral projects, those with a fuse or trip saver protection device, the preferred hardening approach is to underground the overhead circuits. The main cause of storm related outages, especially for weakened structures, is the wind blowing vegetation into conductor, causing structure failures. Therefore, undergrounding lateral lines provides full storm hardening benefits. While rebuilding overhead laterals to a stronger design standard (i.e. bigger and stronger poles and wires) would provide some resilience benefit, it would not solve the vegetation issues, since the high wind speeds can blow tree limbs from outside the trim zone into the conductor.

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a 'poor' condition rating. Additionally, poles with a class that is not better than '2' were also included in these projects. The combination of the physical hardening and automation hardening provides significant resilience benefit for feeders. The physical hardening addresses the weakened infrastructure storm failure component. While the vegetation outside the trim zone is still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than that of laterals. Further, the feeder automation hardening allows for automated switching to perform 'self-healing' functions to mitigate vegetation outside trim zone and other types of outages. The combination of the physical and automation hardening provides a balanced resilience strategy for feeders. It should be noted that this balanced strategy with automation hardening is not available for laterals. As such, undergrounding is preferred approach for lateral hardening while overhead physical hardening combined with automation hardening is the preferred approach for feeders.

At the transmission circuit level, wood poles were identified for hardening by replacing with non-wood materials like steel, spun concrete, and composites. The non-wood materials have a consistent internal strength while wood poles can vary widely and are more likely to fail. Transmission wood poles were grouped at the circuit level into projects.

TEC identified 96 separate transmission access, road, and bridge projects based on field inspections of the system.

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH model identified 59 substations with a flood risk, depending on the hurricane category.

Q16. Why is this approach to hardening project identification important?

A16. This approach to hardening project identification is important for several reasons.

1. The approach is comprehensive. As Table 2 shows, the approach evaluates nearly all the TEC's transmission and distribution (T&D) system. By considering and evaluating the entire system on a consistent basis, the results of the hardening plan provide confidence that portions of the TEC system are not overlooked for potential resilience benefit.
2. By breaking down the entire distribution system by protection zone, the resilience-based planning approach is foundationally customer centric. Each protection zone has a known number of customers and type of customers such as residential, small or large commercial and industrial, and priority customers. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves weak links that could potentially fail in a storm. Rolling assets into projects at the protection device level allows for hardening of

all weak links in the circuit and for capturing the full benefit for customers.

3. The granularity at the asset and project levels allows TEC to invest in portions of the system that provide the most value to customers from a restoration cost reduction, customers impacted (CI), and customer minutes interrupted (CMI) perspective. For example, a circuit may have 10 laterals, the Storm Resilience Model may determine that only 3 out of the 10 should be hardened. Without this granularity, hardening over investment is a concern. The adopted approach provides confidence that the overall plan is investing in parts of the system that provide the most value for customers.
4. The types of hardening projects include the mitigation measures over all the four phases of resilience providing a diverse investment plan. Since storm events cannot be fully eliminated, the diversification allows TEC to provide a higher level of system resilience.
5. The approach balances the use of robust data sets with TEC experience with storm events to develop storm hardening projects. Data-only approaches may provide decisions that don’t match reality, while

people-driven only solutions can be filled with bias. The approach balances the two to better identify types of hardening projects.

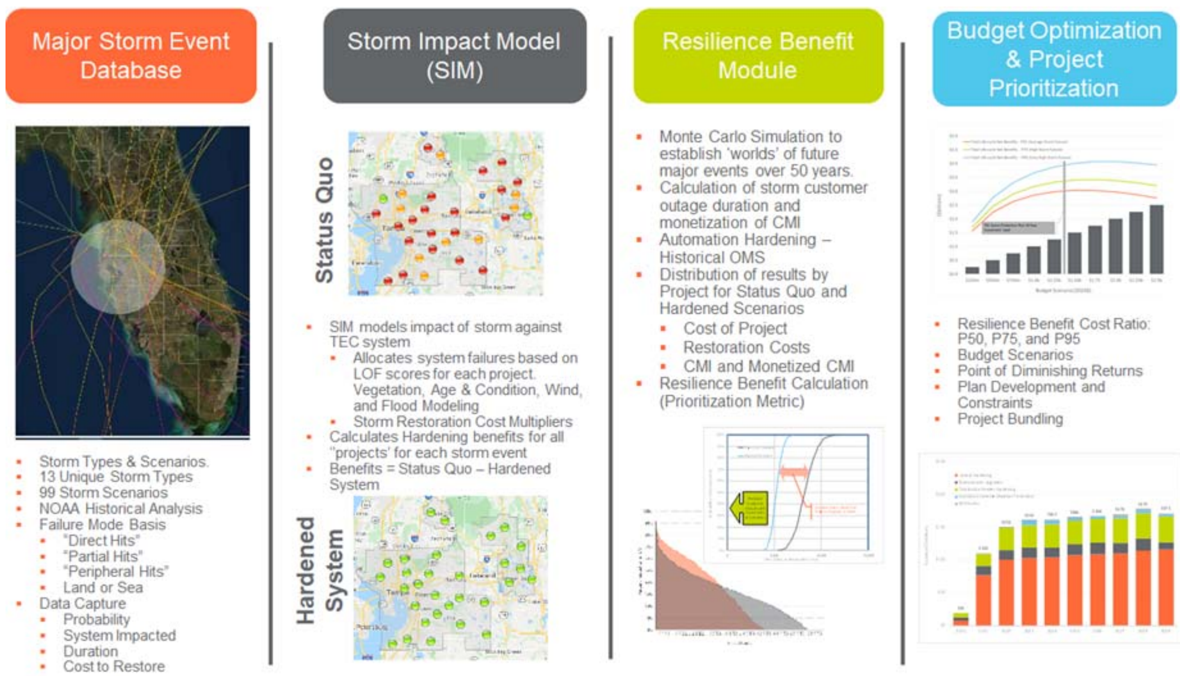
Q17. Please describe the analysis 1898 & Co. conducted for TEC.

A17. 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in the TEC T&D system utilizing a Storm Resilience Model. The Storm Resilience Model consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison across the system. The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, project, and program level. The results of the Storm Resilience Model are:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as CMI

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit. Figure 2 provides an overview of the Storm Resilience Model used to calculate the project benefits and prioritize projects.

Figure 2: Storm Resilience Model Overview



The storms database includes the future 'universe' of potential storm events to impact the TEC service territory. The Major Storm Events Database contains 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios.

Each storm scenario is then modeled within the Storm

Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Likelihood of Failure (LOF) is based on the vegetation density around each conductor asset, the age and condition of the asset base, and the wind zone the asset is in. Substation LOF is based on the SLOSH model results. The Storm Impact Model also estimates the restoration costs and CMI for each of the projects. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is hardened per TEC's hardening standards. The CMI benefit is monetized using the DOE's Interruption Cost Estimator (ICE) for project prioritization purposes.

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (i.e. Category 1 from the Gulf) has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, or Monte Carlo Simulation, to randomly trigger the types storm events to impact the TEC service territory over the next 50 years. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

The Budget Optimization and Project Scheduling model prioritizes the projects based on the highest resilience benefit cost ratio. The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and operational realities (e.g. transmission outages) in scheduling the projects.

This resilience-based prioritization facilitates the identification of the critical hardening projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers get the most value

Q18. Why is it necessary to model storm hardening projects benefits using this resilience-based planning approach and Storm Resilience Model?

A18. The Storm Resilience Model was architected and designed for the purpose of calculating storm hardening project benefit in terms of reduced restoration costs and customer minutes interrupted to build a Storm Protection Plan with the right level of investment that provides the most benefit for customer. It was necessary to model storm hardening projects using the resilience-based planning approach shown in Figure 2 for the following reasons:

1. The benefits of hardening projects are wholly dependent on the number, type, and overall impact of future storms to impact the TEC service territory. Different storms have dramatically different impact to TEC’s system, for instance, in review of TEC’s historical storm reports, it was observed that tropical storm events even 100 to 150 miles away from TEC’s service territory from the Gulf side have greater impact in terms of restoration costs than larger storms 100 to 150 miles away on the Florida or Atlantic side. This is mainly caused by the energy that exists in the storm bands when they reach TEC’s service territory. For this reason, the resilience-based planning approach includes the ‘universe’ of

potential major events that could impact TEC over the next 50 years, this is the Major Storms Event Database. In relation to the conceptual model showing the phases of resilience (Figure 1), I will discuss how the probabilities and system impacts of storm events were developed later in my testimony.

2. Major events cause assets to fail. Assets collectively serve customers. It only takes one asset failure to cause customer outages. The cost to restore the failed assets is dependent on the extent of the damage and resources used to fix the system. The duration to restore affected customers is dependent on the extent of the asset damage and the extent of the damage on the rest of the system. It may only take 4 hours to fix the failed equipment, but customers could be without service for 4 days if crews are busy fixing other parts of the system for 3 days and 20 hours. All of this is dependent on the type of storm to impact the system. Modeling this series of events, the phases of resilience from Figure 1, for the entire system at the asset and project level for both a Status Quo and Hardened scenarios is needed to accurately model hardening project benefits. Therefore, the

resilience-based planning approach includes the Storm Impact Model to calculate the phases of asset and project resilience for each of the 99 storm events for both scenarios. I discuss core data and calculations of the Storm Impact Model to develop the phases of resilience for every asset, project, program, and plan in further detail below in my testimony.

3. The output of the Storms Impact Model is the resilience benefit of each project for each of the 99 storm types. The life-cycle resilience benefit for each hardening project is dependent on the probability of each storm, and the mix of storm events to occur over the life of the hardening projects. A project's resilience value comes from mitigating outages and associated restoration costs not just for one storm event, but from several over the life-cycle of the assets. A future 'world' of major storm events could include a higher frequency of category 1 storms with average level impact and a low frequency of tropical storms with higher impacts. Alternatively, it could include a low frequency of category 1 type storms with high impact and a high frequency of tropical storms with lower impacts.

The number of storm combination scenarios is significant given there are 13 unique types of storm events. To model this range of combinations, the Storm Restoration Model employs stochastic modeling, or Monte Carlo Simulation, to randomly select from the 99 storm events to create a future 'world' of the 13 unique storm events to hit the TEC service territory. The Monte Carlo Simulation creates a 1,000-future storm 'worlds'. From this, the life-cycle resilience benefit of each hardening project can be calculated. This is done in the Resilience Benefit Module, I discuss this in more detail below in my Testimony.

4. To answer the questions of how much hardening investment is prudent and where that investment should be made, it was necessary to include a Budget Optimization and Scheduling Model within the Storm Resilience Model. The Budget Optimization algorithm develops the project plan and associated benefits over a range of budget levels to identify a point of diminishing returns where additional investment provides very little return. The Project Scheduling component uses the preferred budget level and develops an executable plan by prioritizing projects that provide the

most benefit while balancing TEC's technical constraints. I outline this in more detail below.

3. MAJOR STORMS EVENT DATABASE

Q19. Please provide an overview of the Major Storms Event Database and how it was developed.

A19. The Major Storms Event Database includes the 'universe' of storm events that could impact TEC's service territory over the next 50 years. The database describes the phases of resilience (Figure 1) for the TEC high-level system perspective for a range of storm stressors. It was developed collaboratively between TEC and 1898 & Co. It utilizes information from the National Oceanic and Atmospheric Administration (NOAA) database of major storm events, TEC historical storm reports, available information on the impact of major storms to other utilities, and TEC experience in storm recovery. From that information, 13 unique storm types were observed to impact the TEC service territory. For each of the storm types, various storm scenarios were developed to capture the range of probabilities and impacts of each storm type. In total, 99 storms scenarios were developed to capture the 'universe' of storm events to impact the TEC service territory. Table 3 provides a summary of the

Major Storms Event Database. The table includes the ranges of probabilities, restoration costs, impact to the system, and duration of the event.

Table 3: Major Storms Event Database Overview

Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$300 - $1,200	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit - Florida	5% - 8%	$75 - $150	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit - Gulf	2% - 4%	$150 - $300	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25 - $75	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	14.5%	$5 - $15	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$90 - $180	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15 - $90	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11 - $30	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.0	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 21.4	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.6	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

Q20. What does the NOAA data show on the number and types of

major storm events to impact the TEC service territory?

A20. The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 167 years, beginning in 1852. The NOAA major events database was mined for all major event types up to 150 miles from TEC service territory center. The 150-mile radius was selected since many hurricanes can have diameters of 300 miles where some of the hurricane storm bands impact a significant portion of the TEC service territory. Additionally, the database was mined for the category of the storm as it hit the TEC service territory. The analysis of NOAA's database was done for the following types of storm categories:

- **'Direct Hits'** – 50 Mile Radius from the Gulf and Florida directions. The max wind speeds hit all or significant portions of TEC service territory twice, once from the front end and again on the back end of the storm. Additionally, the wind speeds cause all the assets and vegetation to move in one direction as the storm comes in and in the opposite direction as it moves out. This double exposure to the system causes significant system failures.

- **'Partial Hits'** – 51 to 100 Mile Radius. At this radius, the storm bands hit a significant portion of the TEC service territory. Wind speeds are typically at their highest at the outer edge of the storm bands. The storm passes through the territory once, so to speak, minimizing damage relative to a 'direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' small storm.
- **'Peripheral Hits'** – 101 to 150 Mile Radius. Since hurricanes can be 300 miles wide in diameter, some of the storm bands can hit a fairly large portion of the system even if the main body of the storm misses the service area.

Table 4 on the page below includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1852.

Table 4: Historical Storm Summary from NOAA

Event Type	Direct Hits Gulf	Direct Hits Florida	Direct Hits Total	Partial Hits	Peripheral Hits	Total
Cat 5	0	0	0	0	0	0
Cat 4	0	1	1	0	1	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	11	20	31	29	28	88
Tropical Depression	10	8	18	17	NA	35
Total	31	37	68	67	49	184

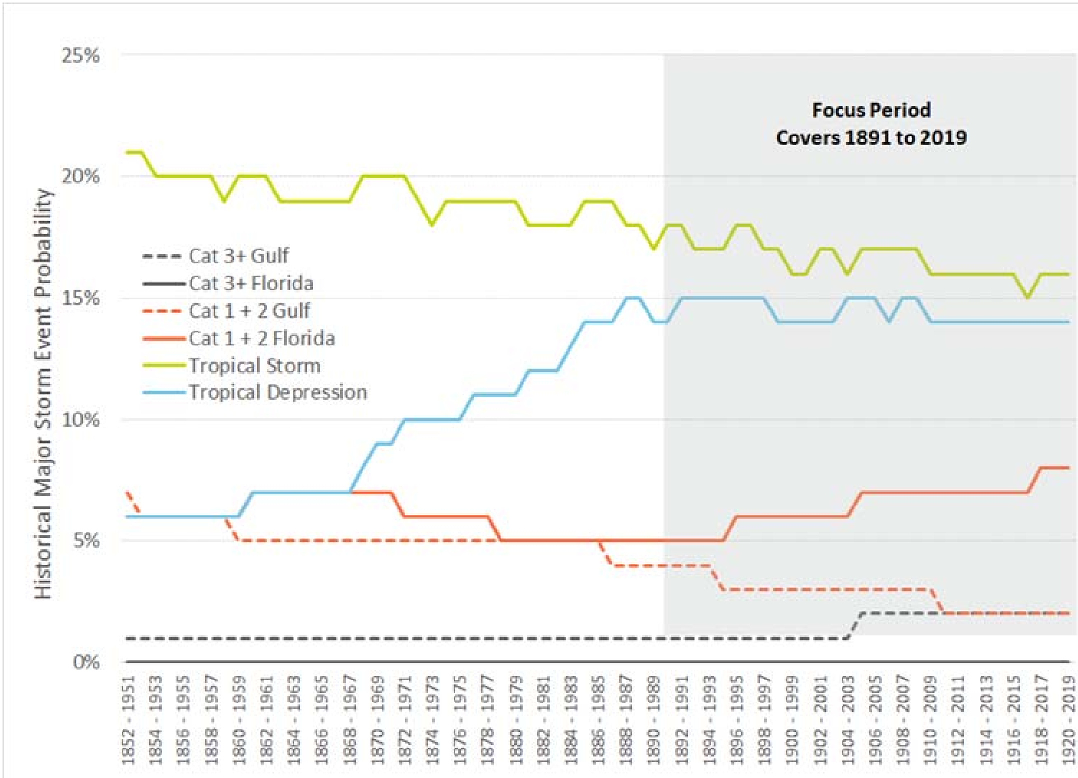
Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Table 4 shows a total of 184 storms to hit the Tampa area since 1852. A total of 68 were direct hits within 50 miles, 67 were partial hits in the 51 to 100-mile radius, and 49 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 184, with one 'Direct Hit'. While there are 10 Category 3 types storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 46 percent of the events come from the Gulf of Mexico while the other 54 percent come over Florida.

Q21. What analysis of this historical storm information was done to determine the storm probability ranges?

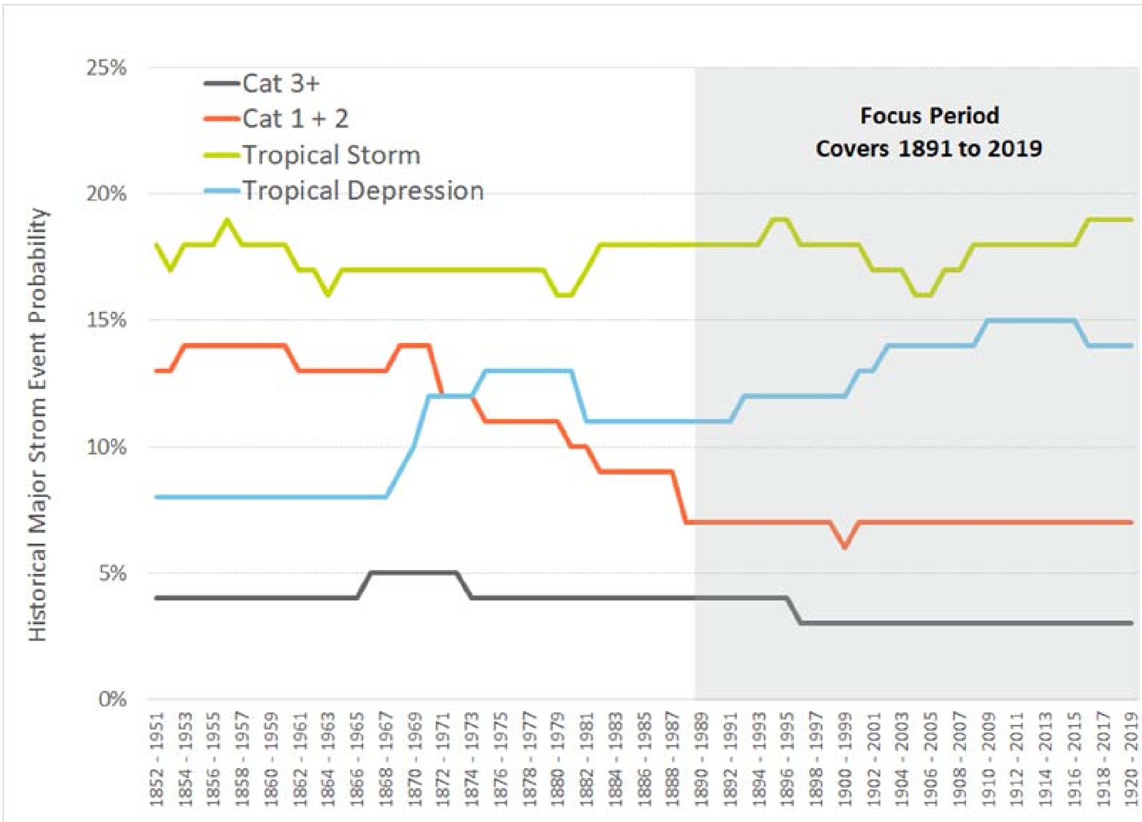
A21. 1898 & Co. converted the storm information from Table 4 above to show the total storm count for 100-year rolling average starting with the period of 1852 to 1951 ending with the period 1920 to 2019. This provides 69, 100 year periods. This was done for each of the 13 unique storm events. The counts of each 100 year period for each storm type were then converted to probabilities. Starting on the page below, Figure 3, Figure 4, and Figure 5 show the 100 year rolling storm probability for "direct hits" (50 miles), "partial hits" (51 to 100 miles), and "peripheral hits" (101 - 150 miles), respectively.

Figure 3: "Direct Hits" (50 Miles) 100 Year Rolling Probability



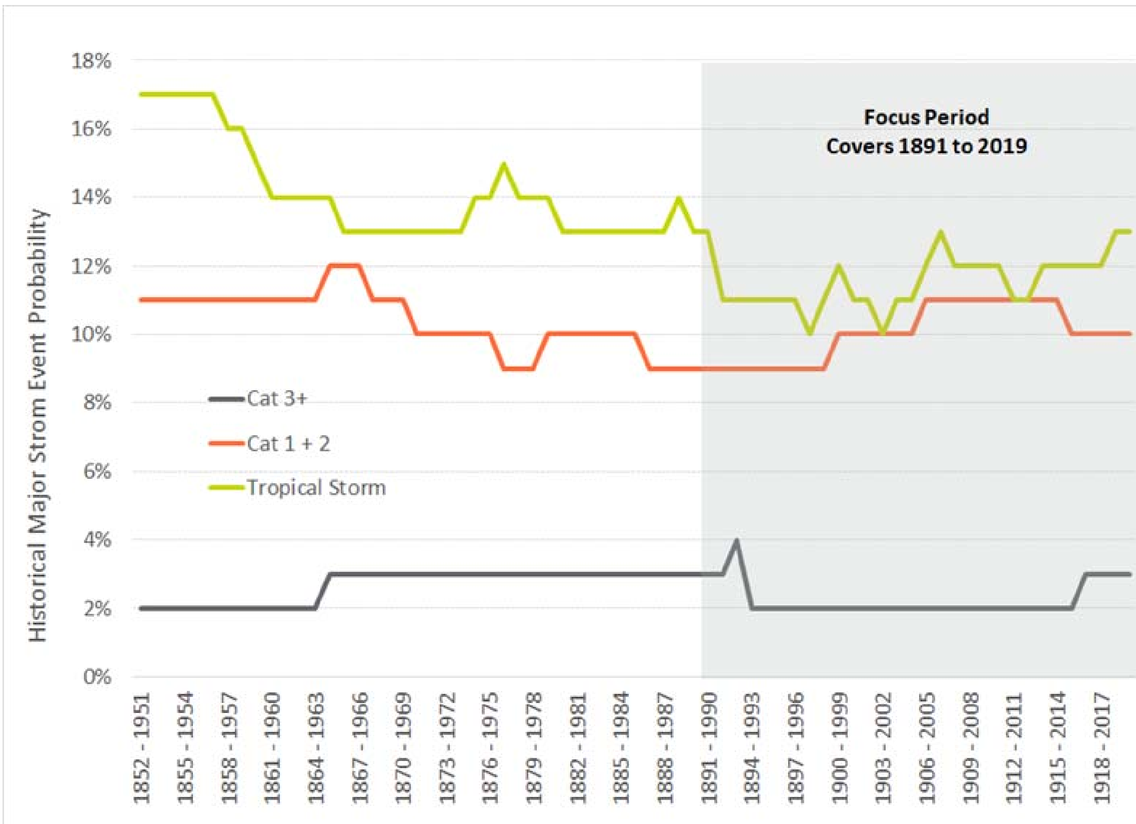
Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 4: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability



Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 5: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability



Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Each of the figures show a relative stability in the 100 year probability levels for the last 30 periods corresponding to storm events from 1891 through 2019. This time horizon served as the basis for developing the probability ranges for the 13 unique storm events.

Q22. How were the storm impact ranges developed?

A22. The range of system impacts for each storm scenario were developed based on historical storm reports from TEC and augmented by the TEC's team experience with historical storm events. The database includes events that have not recently impacted TEC's service territory. The approach followed an iterative process of filling out more known impact information from recent events and developing impacts for those events without impact data based on their relative storm strength to the more known events.

4. STORM IMPACT MODEL

Q23. Please provide an overview of the Storm Impact Model.

A23. The Storm Impact Model describes the phases of resilience, Figure 1, for each potential hardening project on the TEC T&D system for each storm stressor scenario from the Major Storms Event Database. Specifically, it identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, access sites, and substations that fail for each type of storm in the Major Storms Event Database. The model also estimates the restoration costs associated with the specific sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both the Status Quo and Hardened scenario. The Hardened scenario assumes the assets that make up each project have been hardened. The Storm Impact Model then calculates the benefit of each hardening project from a reduced restoration cost, CMI, and monetized CMI perspective.

Q24. You have mentioned that the Storm Resilience Model employs a data-driven decision-making methodology. Please describe what core data sets that are in the model and how they are used in the resilience benefit calculation.

A24. The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms at a very granular system level to model the benefits of each hardening project for each storm scenario. TEC's data systems include a connectivity model that allows for the linkage of three foundational data sets used in the Storm Impact Model – the Geographical Information System (GIS), the Outage Management System (OMS), and Customer.

GIS - The GIS provides the list of assets in TEC's system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management bottom-up based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the Storm Protection Plan. The strategic assignment of assets to projects and the value of the approach is discussed above.

OMS - The OMS includes detailed outage information by cause code for each protection device over the last 19 years. The Storm Impact Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include Major Event Days (MED), vegetation, lightening, and storm-based outages. The OMS served as the link between customer class information and the GIS to provide the Storm Impact Model with the information necessary to understand how many customers and what type of customers would be without service for each project. The OMS data also served as the foundation for calculating benefits for feeder automation projects.

Customer - The third foundational data set is customer count and customer type information that featured connectivity to the GIS and OMS systems. This allowed the Storm Impact Model to directly link the number and type of customers impacted to each project and the project's assets. This customer information is included for every distribution asset in TEC system. The customer information is used within the Storm Impact Model to calculate each storms CMI (customers affected * outage duration) for each lateral or feeder project.

Vegetation Density - The vegetation density for each overhead conductor is a core data set for identifying and prioritizing resilience investment for the circuit assets since vegetation blowing into conductor is the primary failure mode for major storm event for TEC. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor (approximately 240,000 spans) utilizing tree canopy data and geospatial analytics.

Wood Pole Condition - A compromised, or semi-compromised, pole will fail at lower dynamic load levels then poles with their original design strength. The Storm Impact Model utilizes wood pole inspection data within 1898 & Co.'s asset health algorithm to calculate an Asset Health Index (AHI) and 'effective' age for each pole.

Wind Zones - Wind zones have been created across the

United States for infrastructure design purposes. The National Electric Safety Code (NESC) provides wind and ice loading zones. The zones show that wind speeds are typically higher closer to the coast and lower the further inland. The Storm Impact Model utilizes the provided wind zone data from the public records and the asset geospatial location from GIS to designate the appropriate wind zone.

Accessibility - The accessibility of an asset has a tremendous impact on the duration of the outage and the cost to restore that part of the system. Rear lot poles take much longer to restore and cost more to restore than front lot poles. The Storm Impact Model performs a geospatial analysis of each structure to identify if there is road access or if the asset is in a deep right-of-way (ROW).

Flood Modeling - The model also includes detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations applied to the specific location shoreline, Tampa in this case, incorporating the unique bay and river configurations, water depths, bridges, roads, levees and other physical features to establish surge height. These results are simulated several thousand times to develop the Maximum of the Maximum Envelope of Water, the worst-case scenario for each storm category. The SLOSH model results were overlaid with the location of TEC's 216 substations to estimate the height of above the ground elevation for storm surge. The SLOSH model identified 59 substations with flooding risk depending on the hurricane category.

Q25. What were the results of the vegetation density algorithm?

A25. Figure 6 and Figure 7 on the page below show the range of vegetation density for OH Primary and Transmission Conductor, respectively. The figures rank the conductors from highest to lowest level of vegetation density. As shown in the figures, approximately 30 to 35 percent of the OH Primary and Transmission Conductor have near zero tree canopy coverage, while approximately 65 to 70 percent have some level of coverage all the way up to 100 percent coverage.

Figure 6: Vegetation Density on TEC Primary Conductor

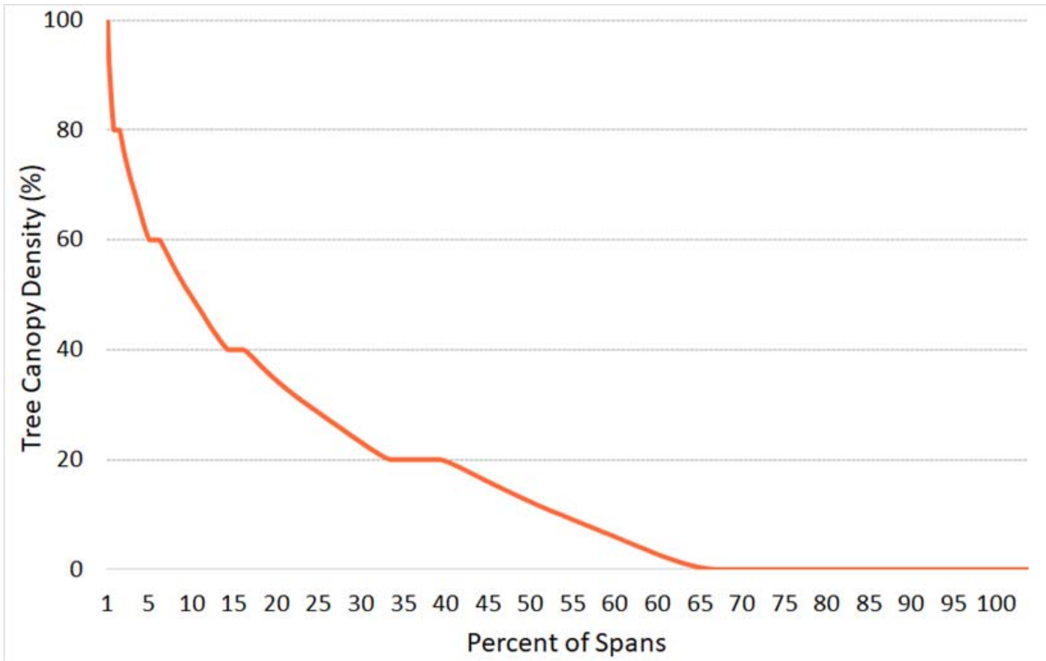
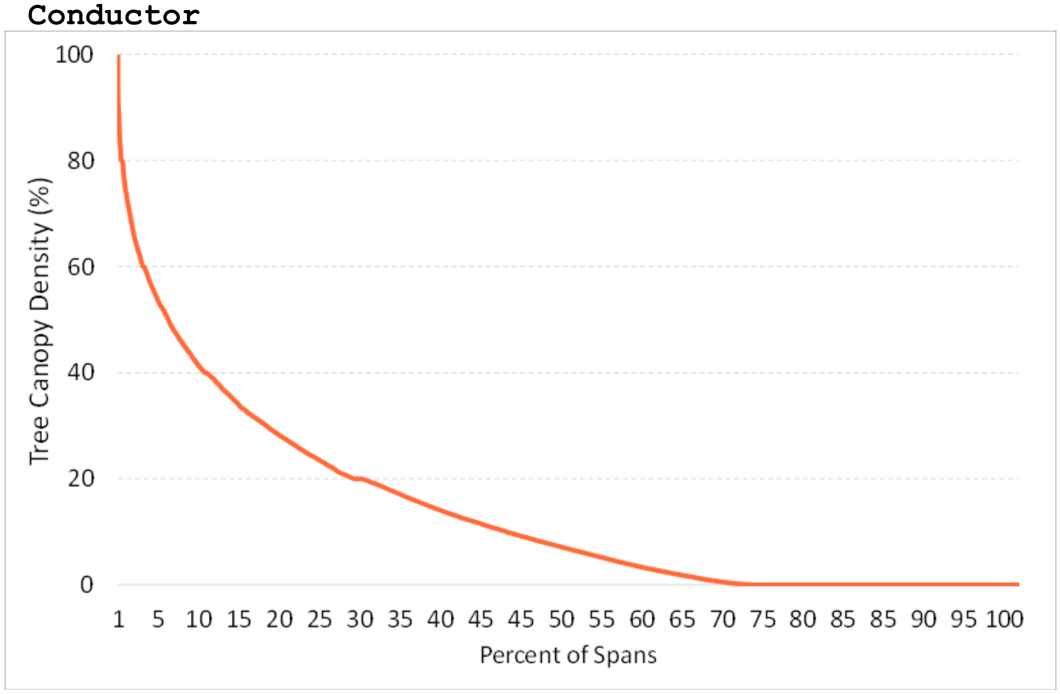


Figure 7: Vegetation Density on TEC Transmission Conductor



Q26. How are asset and system failures during major storm events identified in the Storm Impact Model hardening projects?

A26. The Storm Impact Model identifies system failures based on the primary failure mode of the asset base. The model identifies the parts of the system that are likely to fail given the specific storm event from the Major Storms Event Database.

For circuits, the main cause of failure is wind blowing vegetation onto conductor causing conductor or structures to fail. If structures (i.e. wood poles) have any deterioration, for example rot, they are more susceptible to failure. The Storm Impact Model calculates a storm LOF score for each asset based on a combination of the vegetation rating, age and condition rating, and wind zone rating. The vegetation rating factor is based on the vegetation density around the conductor. The age and condition rating utilizes expected remaining life curves with the asset's 'effective' age, determined using condition data. The wind zone rating is based on the wind zone that the asset is located within. The Storm Impact Model includes a framework that normalizes the three ratings with each other to develop one overall storm LOF score for all circuit assets. The project level scores are equal to the sum of the asset scores normalized for length. The project level scores are then used to rank each project against each other to identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

The model determines which substations are likely to flood during various storm types based on the flood modeling analysis. That analysis provides the flood level, meaning feet of water above the site elevation, for various storm types. Only the storm scenarios with hurricanes coming from the Gulf of Mexico provide the necessary condition for storm surge that would cause substation flooding.

The site access dataset includes a hierarchy of the impacted circuits. Using this hierarchy, each site access LOF is equal to the total LOF of the circuits it provides access to.

Q27. How are restoration costs allocated to the asset base for each major storm events?

A27. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration cost multipliers above planned replacement costs. These multipliers were developed by TEC and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. For each storm event, the restoration costs at the asset level are aggregated up to the project level and then weighted based on the project LOF and the overall restoration costs outlined in the Major Event Storms Database.

Q28. How are customer outage durations calculated in the model for each major storm event?

A28. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset and project in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefit are also monetized.

Q29. Why were CMI benefit monetized?

A29. The CMI benefits were monetized for project prioritization purposes. The Storm Impact Model calculates each hardening project's CMI and restoration cost reduction for each storm scenario. In order to prioritize projects, a single prioritization metric is needed. Since CMI is in minutes and restoration costs is in dollars, the resilience-based planning approach monetized CMI. The monetized CMI benefit is combined with the restoration cost benefit for each project to calculate a total resilience benefit in dollars.

Q30. How was the CMI benefit monetized?

A30. CMI was monetized using DOE's ICE Calculator. The ICE Calculator is an electric outage planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability or resilience improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE). The ICE calculator incudes the cost of an outage for different types of customers. The calculator was extrapolated for the longer outage durations associated with storm outages. The extrapolation includes diminishing costs as the storm duration extends. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level.

Q31. How are the storm specific resilience benefits calculated for each project by major storm event?

A31. The Storm Impact Model calculates the storm restoration costs and CMI for the 'Status Quo' and Hardening Scenarios for each project by each of the 99 storm events. The delta between the two scenarios is the benefit for each project. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age & condition, wind zone, flood level, restoration costs, duration, and customers impacted) for each project.

The output from the Storm Impact Model is a project by project probability-weighted estimate of annual storm restoration costs, annual CMI, and annual monetized CMI for both the 'Status Quo' and Hardened Scenarios for all 99 major storm scenarios. The following section describes the methodology utilized to model all 99 major storms and calculate the resilience benefit of each project.

5. RESILIENCE BENEFIT MODULE

Q32. Please provide an overview of the Resilience Benefit Calculation Module

A32. The Resilience Benefit Calculation Module of the Storm Resilience Model uses the annual benefit results of the Storm Impact Model and the estimated project costs to calculate the net benefits for each project. Since the benefits for each project are dependent on the type and frequency of major storm activity, the Resilience Benefit Module utilizes stochastic modeling, or Monte Carlo Simulation, to randomly select a thousand future worlds of major storm events to calculate the range of both 'Status Quo' and Hardened restoration costs and CMI. The benefit calculation is performed over a 50-year time horizon, matching the expected life of hardening projects.

The feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (OMS) includes 19 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

Q33. What economic assumptions are used in the life-cycle Resilience Benefit Module?

A33. The resilience net benefit calculation includes the following economic assumptions.

- 50 year time horizon – most of the hardening infrastructure will have an average service life of 50 or more years.
- 2 percent escalation rate
- 6 percent discount rate

Q34. How were hardening project costs determined?

A34. Project costs were estimated for over 20,000 projects in the Storm Resilience Model. Some of the project costs were provided by TEC while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) that were then multiplied by unit cost estimates to calculate the project costs.

Distribution Lateral Undergrounding – The GIS and accessibility algorithm calculated the following scope items for each of the lateral undergrounding projects:

- Miles of overhead conductor for 1, 2, and 3 phase laterals
- Number of overhead line transformers, including number of phases, that need to be converted to pad mounted transformers
- Number of meters connected through the secondary via overhead line.

TEC provided unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) to calculate the project cost. The unit cost estimates are based on supplier information and previous undergrounding projects.

Transmission Asset Upgrades - The Transmission Asset

Upgrades program project costs are based on the number of wood poles by class, type (H-Frame vs monopole), and circuit voltage. TEC provided unit cost estimates for each type of pole to be replaced. The project costs equal the number wood poles on the circuit multiplied by the unit replacement costs.

Substation Extreme Weather Hardening - The project costs for the Substation Extreme Weather Hardening program are based on the perimeter of each substation multiplied by the unit cost per foot to install storm surge walls. The costs per foot vary by the required height of the wall. The substation wall height is based off the needed height to mitigate the flooding from the SLOSH model results.

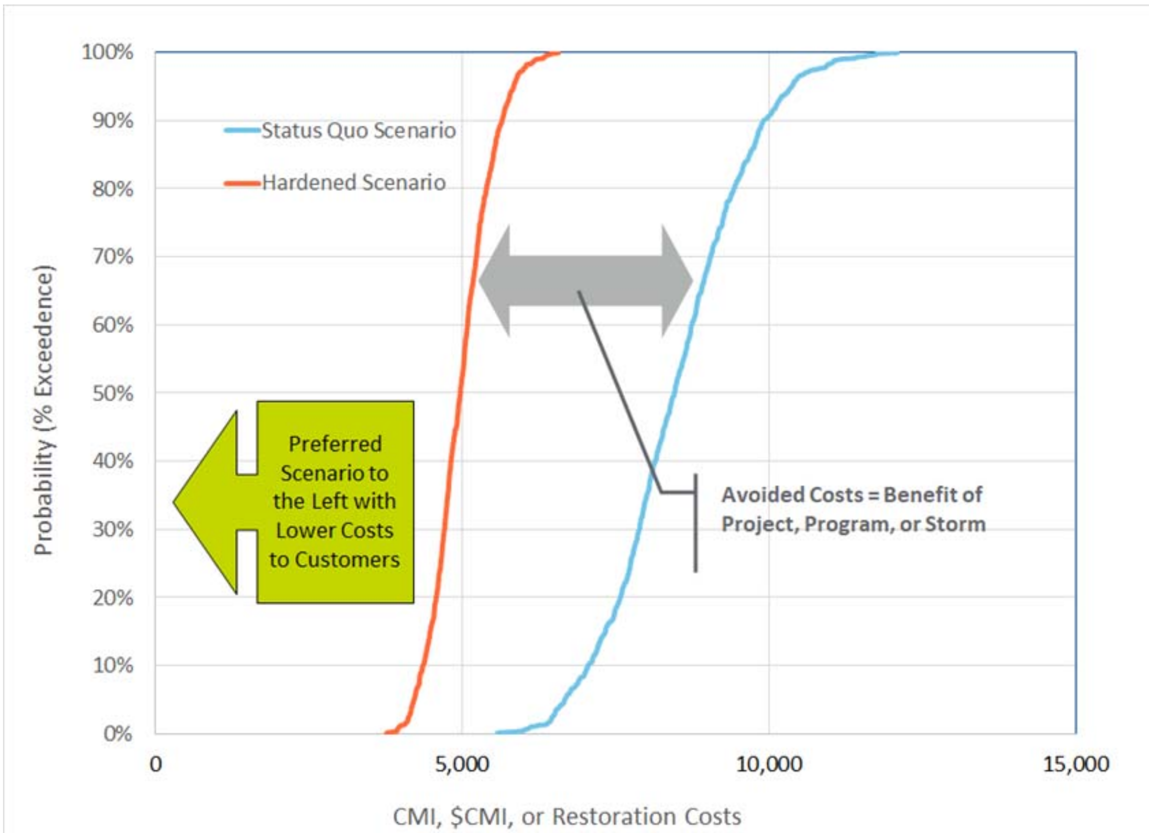
Distribution Overhead Feeder Hardening - The distribution overhead feeder hardening project costs are based on the number of wood poles that don’t meet current design standards for storm hardening and the cost to include automation. TEC provided unit replacement costs based on the accessibility of the pole as well as the cost to add automation to each circuit. Automation hardening cost estimates include the cost to add reclosers, pole replacements, re-conductor portions of the line, and substation upgrades that may be needed to handle load transfer.

Transmission Access Enhancements - TEC provided all the project costs for the Transmission Access Enhancements. The cost estimates were based on the length of the bridge or road. Those lengths were developed using geospatial solutions using TEC's GIS for each problem area.

Q35. How are the resilience results of the Monte Carlo Simulation displayed and how should they be interpreted?

A35. The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. In layman's terms, the thousand results are sorted from lowest to highest (cumulative ascending) and then charted. Figure 8 on the page below shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios.

Figure 8: Status Quo and Hardened Results Distribution Example



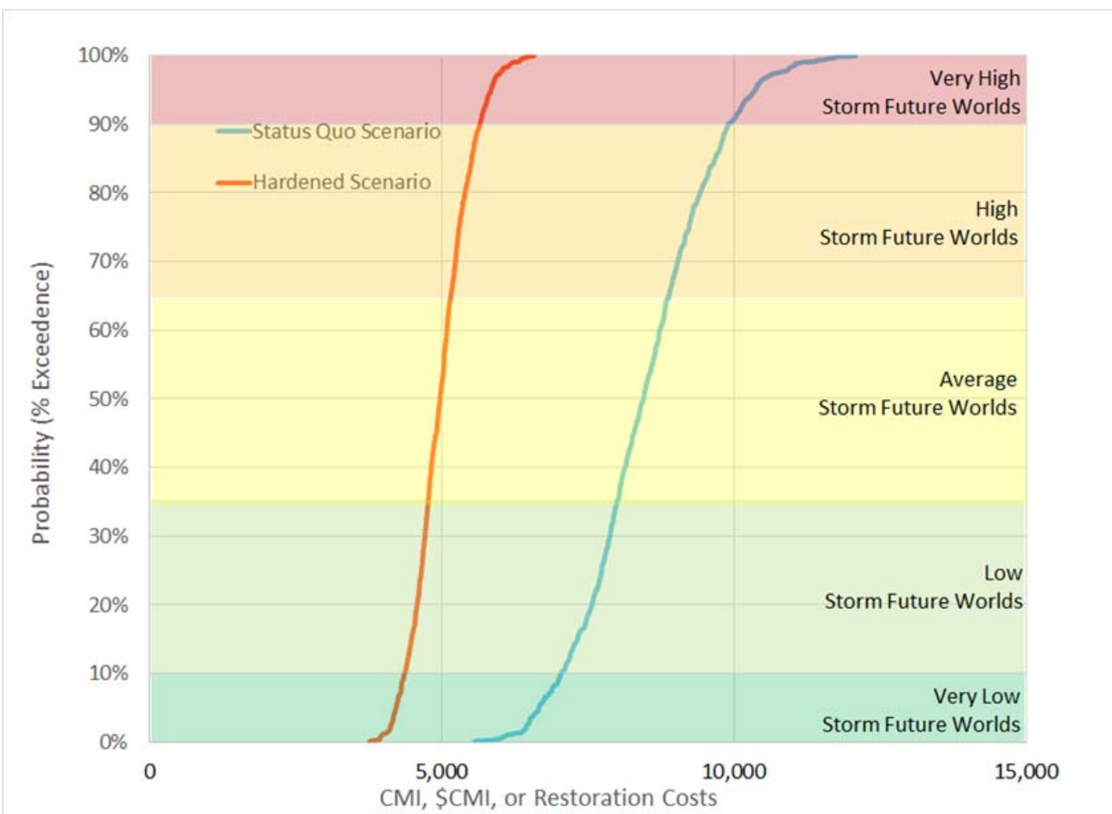
Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e. vertical) the less range in the result. The more horizontal the slope the wider the range and variability in the results.

Q36. How do S-Curves map to potential Future Storm Worlds?

A36. Figure 9 below provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

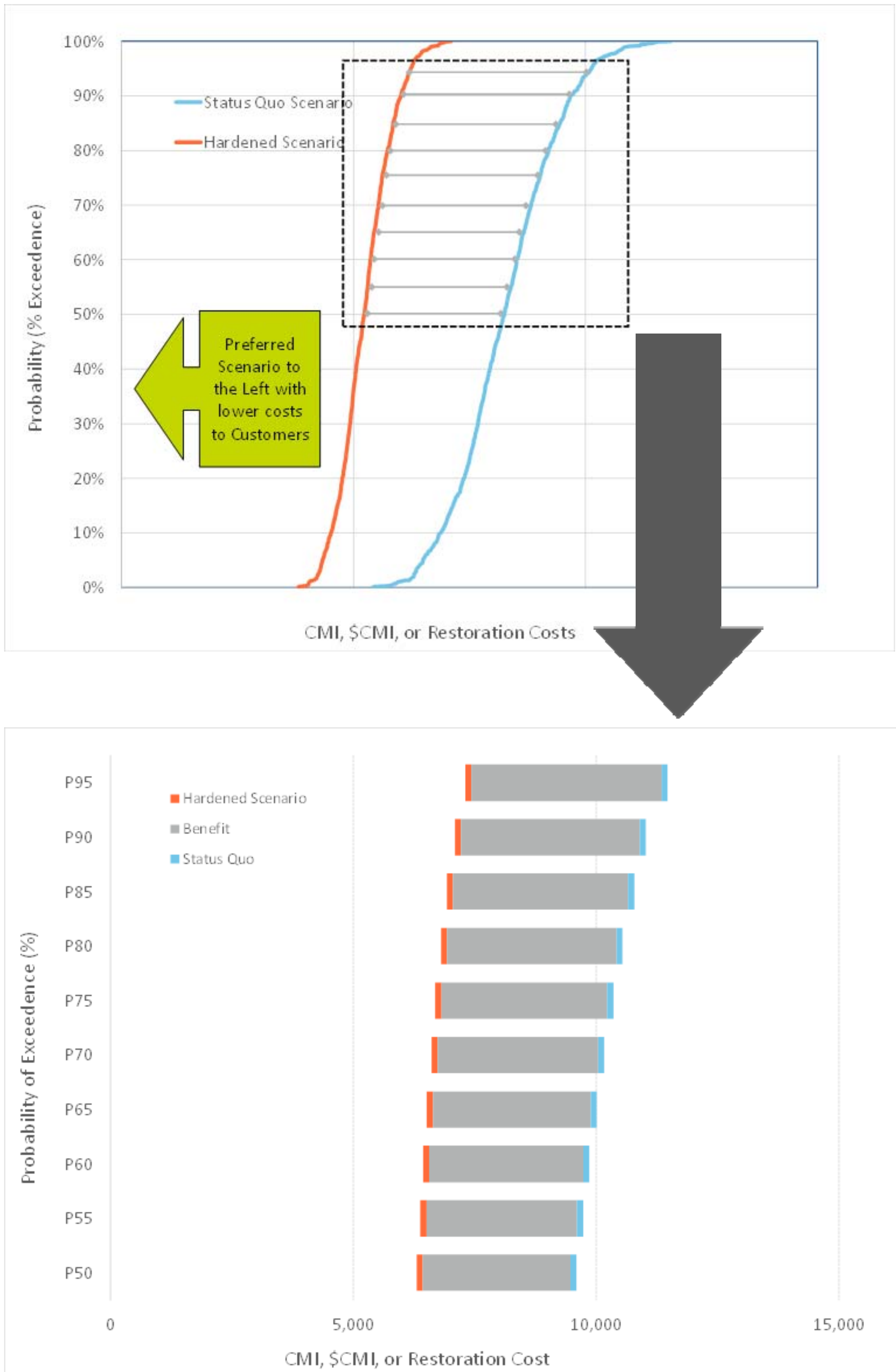
Figure 9: S-Curves and Future Storms



Q37. How are the S-Curves used to display the resilience benefit results?

A37. For the storm resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Rather than show the entire S-curve, the resilience results will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 10 on the page below illustrates this concept of looking at the top part of the S-curves and showing the P-values.

Figure 10: S-Curves and Resilience Focus



Q38. Please describe the analysis to calculate resilience benefit for automation hardening projects.

A38. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event, the 'pit' of the resilience conceptual model described in Figure 1.

The resilience benefit for feeder automation was estimated using historical Major Event Day (MED) outage data from the OMS. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days. TEC has outage records going back 19 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 19 years.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. The Storm Resilience Model extrapolates the 19 years of benefit calculation to 50 years to match the time horizon of the other projects. Additionally, the CMI was monetized and discounted over the 50-year time horizon to calculate the net present value (NPV). The NPV calculation assumed a replacement of the reclosers in year 25; the rest of the feeder automation investment has an expected life of 50 years or more. The monetization and discounted cash flow methodology was performed for project prioritization purposes.

Q39. Please provide an example of this calculation.

A39. A historical outage may include a down pole from a storm event, causing the substation breaker to lock out resulting in a four-hour outage for 1,500 customers, or 360,000 CMI (4*1500*60). The Storm Resilience Model re-calculates the outages as 400 customers without power for four hours, or 96,000 CMI. That example provides a reduction in CMI of over 70 percent.

Q40. What are the results of this analysis for the automation hardening projects?

A40. Figure 11 and Figure 12 starting on the page below show the percent decrease in CMI and monetized CMI for all circuits ranked from highest to lowest from left to right. The figures also include the benefits to all outages.

Figure 11: Automation Hardening Percent CMI Decrease

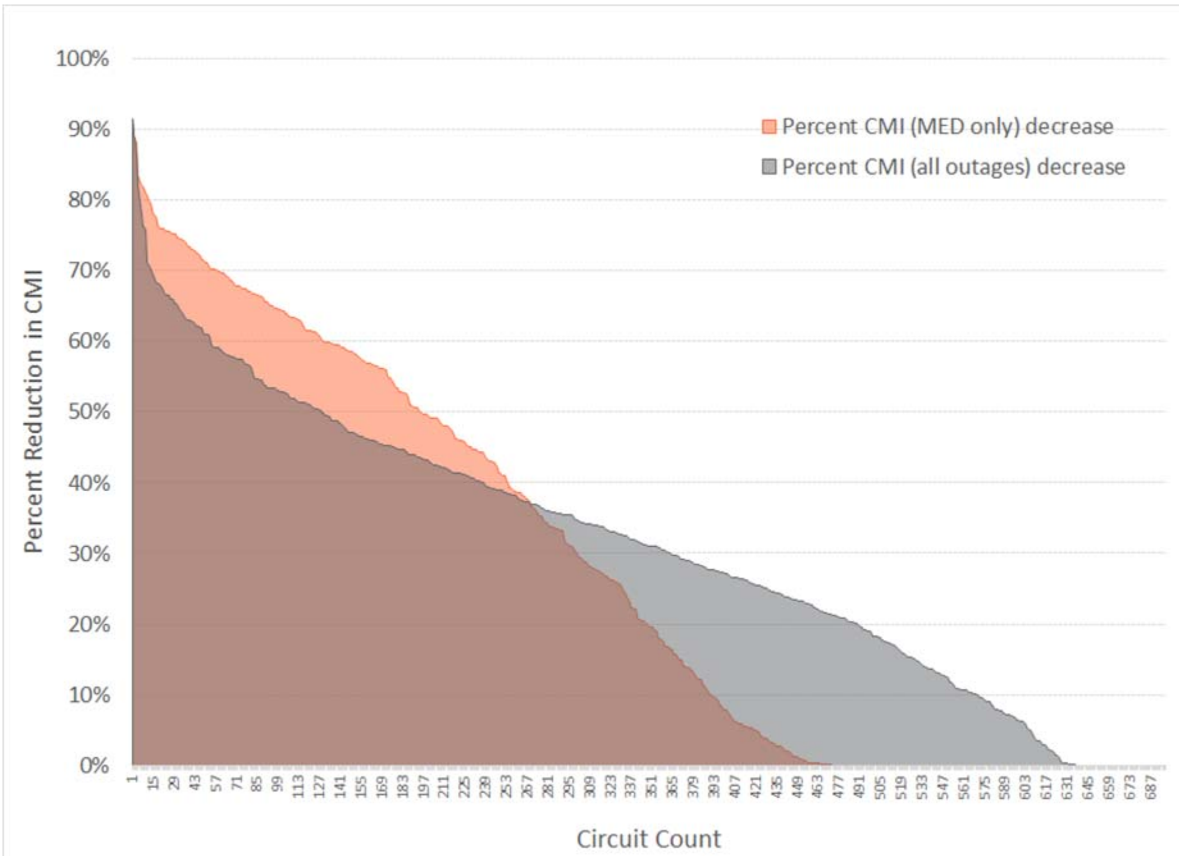
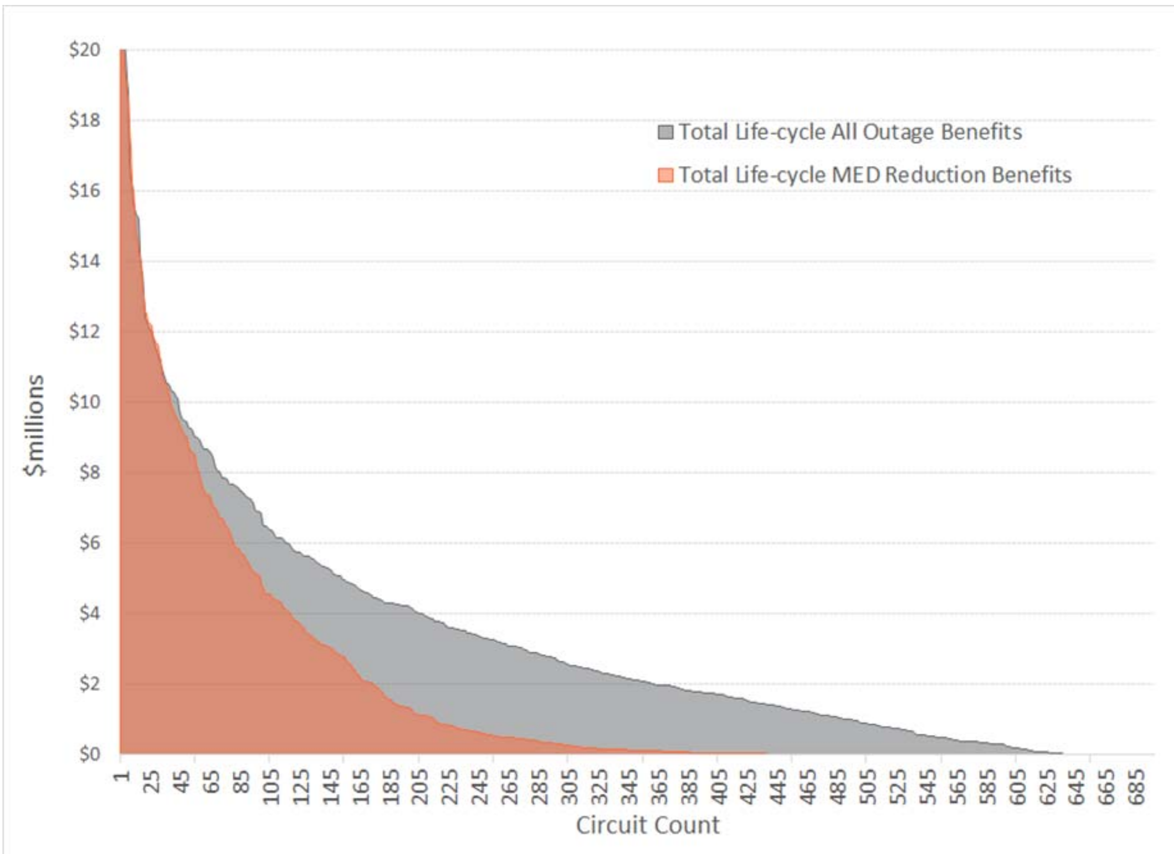


Figure 12: Automation Hardening Monetization of CMI Decrease



Q41. What are the specific outputs from the Resilience Benefit module?

A41. The Resilience Benefit Module includes the following values for each project:

- CMI 50-year Benefit
- Restoration Cost 50-year NPV Benefit
- Life-cycle 50 year NPV gross Benefit (monetized

CMI benefit + restoration cost benefit)

- Life-cycle 50 year NPV net Benefit (monetized CMI benefit + restoration cost benefit – project costs)

Each of these values includes a distribution of results from the 1,000 iterations. For ease of understanding and in alignment with the resilience-based strategy, the approach focuses on the P50 and above values, specifically considering:

- P50 – Average Storm Future
- P75 – High Storm Future
- P95 – Extreme Storm Future

6. BUDGET OPTIMIZATION AND PROJECT SCHEDULEING

Q42. How were hardening projects prioritized?

A42. All the projects are evaluated and prioritized using the same criteria allowing all 20,459 projects to be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50 year NPV gross benefit value listed above. The ranking is performed for each of the P-values (P50, P75, and P95) as well as a weighted value.

Performing prioritization for the four benefit cost ratios is important since each project has a different slope in their benefits from P50 to P95. For instance, many of the lateral undergrounding projects have the same benefit at P50 as they do at P95. Alternatively, many of the transmission asset hardening projects are minorly beneficial at P50 but have significant benefits at P75 and even more at P95. TEC and 1898 & Co. settled on a weighting on the three values for the base prioritization metric, however, investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

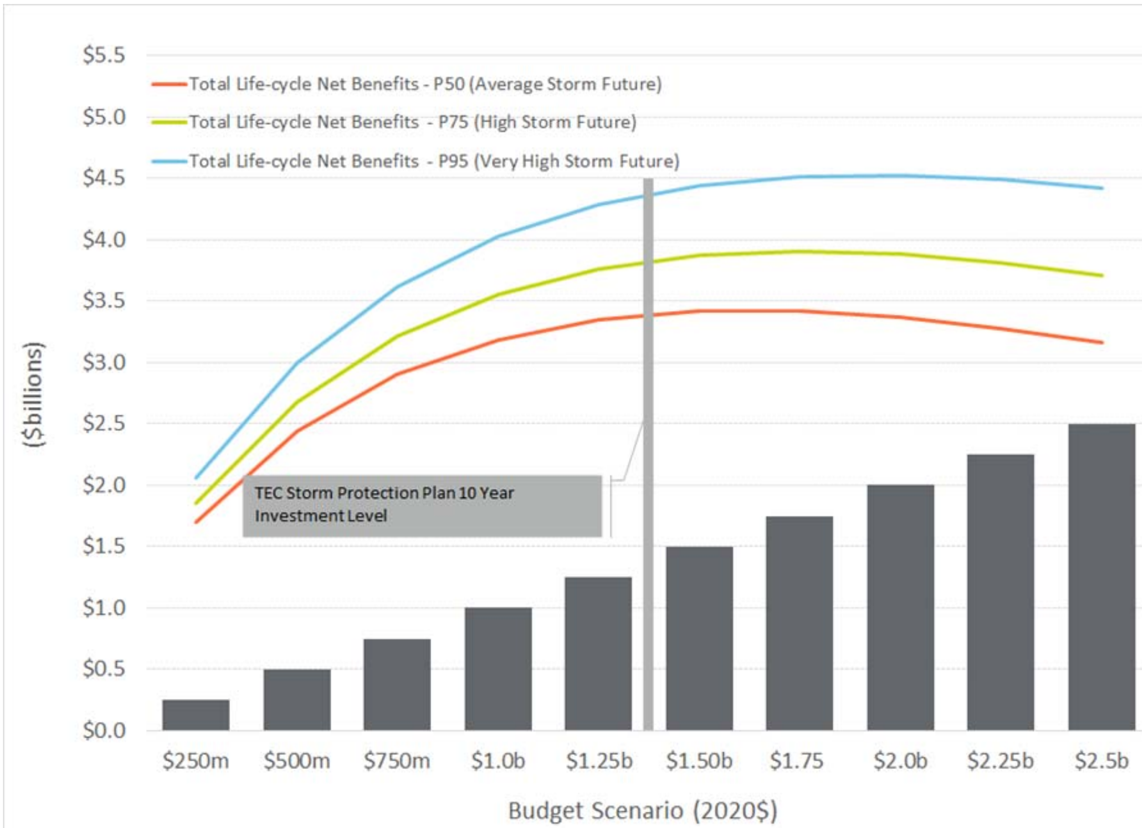
Q43. How and why was the budget optimization performed?

A43. The Storm Resilience Model performs project prioritization across a range of budget levels to identify the appropriate level of resilience investment. The goal is to identify where 'low hanging' resilience investment exists and where the point of diminishing returns occurs. Given the total level of potential investment the budget optimization analysis was performed in $250 million increments up to $2.5 billion. For each budget level, the optimization model selects the projects with the highest benefit cost ratio to hardening in the next 10 years. The model then strategically groups projects by type of program and circuit. For instance, all the selected laterals on a circuit are scheduled for undergrounding in the same year. This allows TEC to gain capital deployment efficiencies by deploying resources to the same geographical area at one time.

Q44. What were the results of the budget optimization analysis?

A44. Figure 13 on the page below shows the results of the budget optimization analysis. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95.

Figure 13: Budget Optimization Results



The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion.

Q45. What conclusions can be made from the results of the budget optimization analysis?

A45. The budget optimization results show that TEC's overall investment level is right before the point of diminishing returns showing that TEC's plan has an appropriate level of investment capturing the hardening projects that provide the most value to customers.

Q46. How was the overall investment level set and projects selected?

A46. TEC and 1898 & Co. used the Storm Resilience Model as a tool for developing the overall budget level and the budget levels for each category. It is important to note that the Storm Resilience Model is only a tool to enable more informed decision making. While the Storm Resilience Model employs a data-driven decision-making approach with robust set of algorithms at a granular asset and project level, it is limited by the availability and quality of assumptions. In developing the TEC Storm Protection plan project identification and schedule, the TEC and 1898 & Co team factored in the following:

- Resilience benefit cost ratio including the weighted, P50, P75, and P95 values.
- Internal and external resources available to execute investment by program and by year.
- Lead time for engineering, procurement, and

construction

- Transmission outage and other agency coordination.
- Asset bundling into projects for work efficiencies.
- Project coordination (i.e. project A before project B, project Y and project Z at the same time)

7. RESILIENCE BENEFIT RESULTS

Q47. What is the investment profile of the Storm Protection Plan?

A47. Table 5 on the page below shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second, accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total, with substations and site access making up 2.2 percent and 1.0 percent, respectively. The plan includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

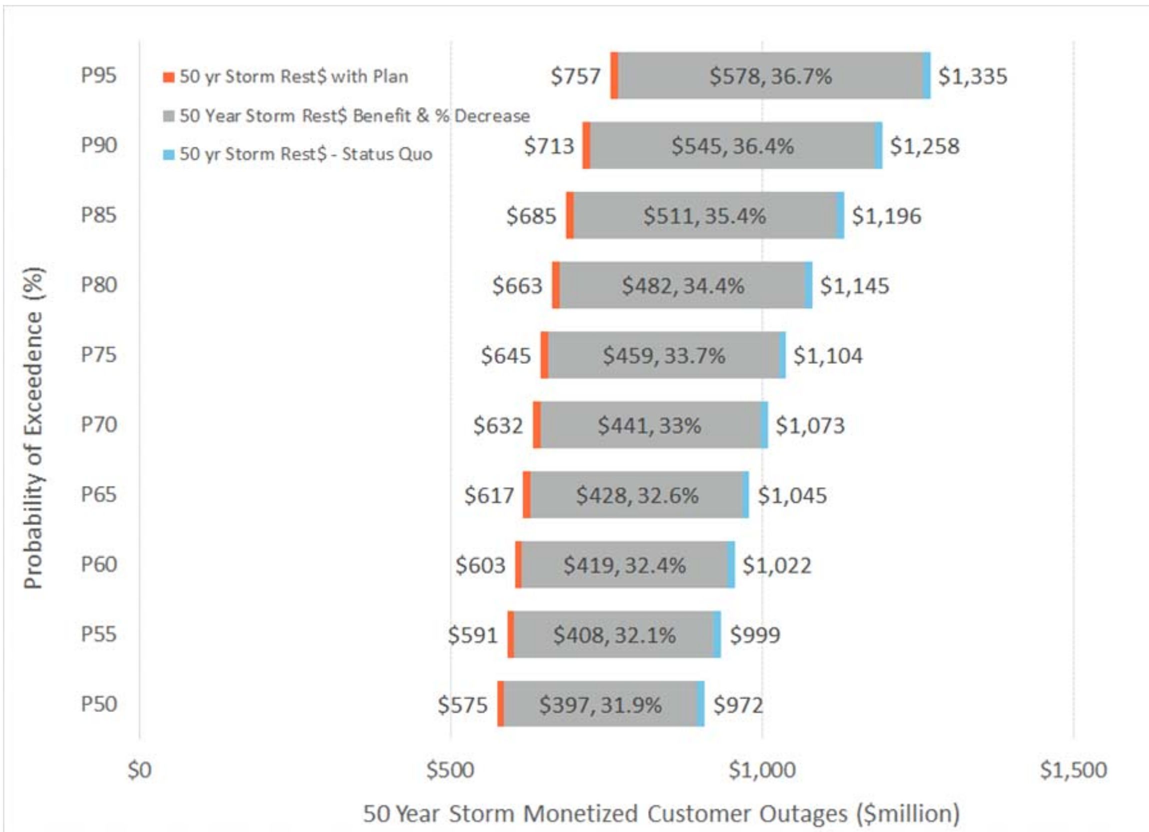
Table 5: Storm Protection Plan Investment Profile by Program (Nominal $000)

Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Transmission Site Access	Total
2020	$8,000	$5,600	$0	$6,200	$0	$19,700
2021	$79,500	$15,200	$0	$15,400	$1,400	$111,500
2022	$108,100	$15,000	$0	$29,600	$1,500	$154,200
2023	$101,400	$16,500	$0	$33,400	$1,600	$152,900
2024	$107,000	$11,900	$7,300	$32,500	$1,700	$160,400
2025	$110,800	$19,000	$5,500	$33,200	$1,300	$169,900
2026	$114,000	$17,700	$4,700	$33,800	$400	$170,600
2027	$111,400	$16,300	$6,700	$32,800	$3,300	$170,500
2028	$115,500	$19,600	$5,200	$36,400	$2,000	$178,700
2029	$121,100	$12,100	$2,900	$36,300	$1,700	$174,000
Total	$976,800	$148,900	$32,400	$289,600	$14,800	$1,462,500

Q48. What are the restoration cost benefits of the plan?

A48. Figure 14 on the page below shows the range in restoration cost reduction at various probability of exceedance levels. As a refresher, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 level represents a future world where storms are more frequent and intense, and the P90 and P95 levels represent a future world where storm frequency and impact are all high.

Figure 14: Storm Protection Plan Restoration Cost Benefit

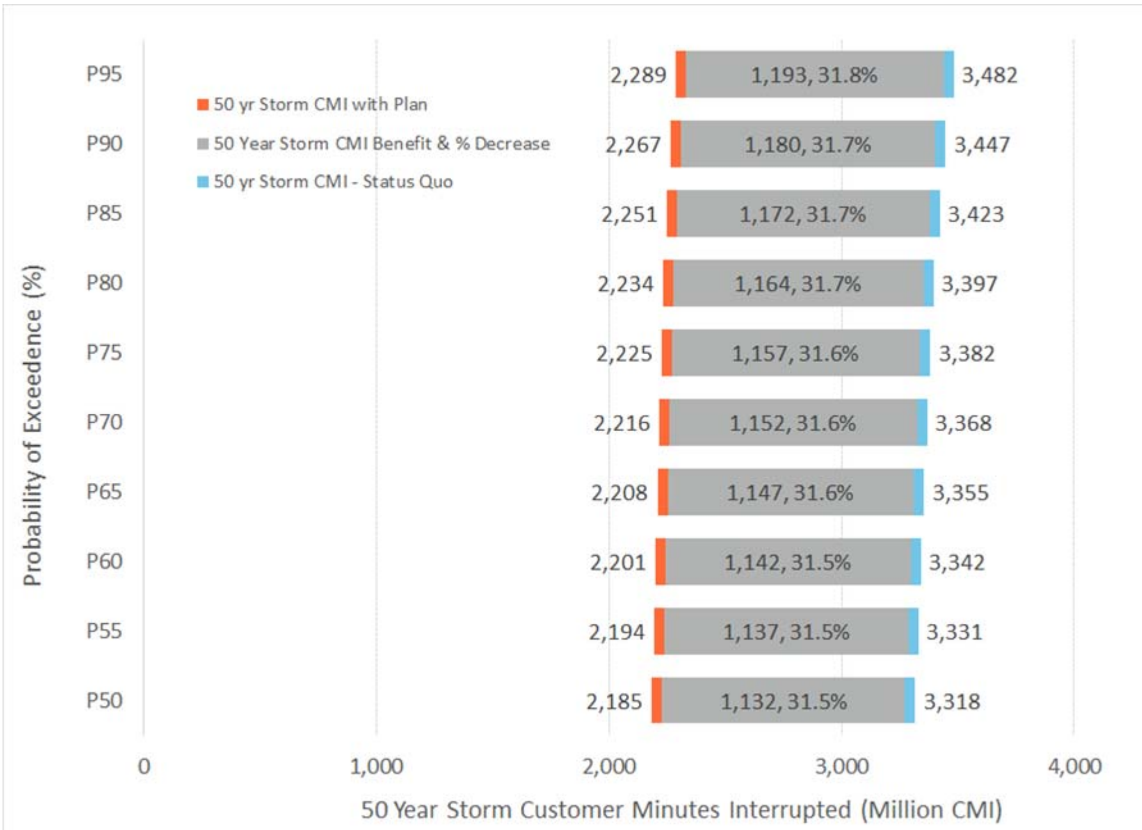


The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration costs decrease benefit is approximately 36 to 53 percent of the project costs.

Q49. What are the customer outage benefits of the plan?

A49. Figure 15 on the page below shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

Figure 15: Storm Protection Plan Customer Benefit



Q50. What are the key take-aways from how resilience-based planning assessment was performed?

A50. The follow are the key take-aways from how the resilience-based planning assessment was performed in the Storm Resilience Model:

- **Customer and Asset Centric:** The model is foundationally customer and asset centric in how it "thinks" with the alignment of assets to protection devices and protection devices to customer information (number, type, and priority). Further, the focus of investment to hardening all asset weak links that serve customers shows that the Storm Resilience Model is directly aligned with the intent of the statute to identify hardening projects that provide the most benefit to customers. Additionally, with this customer and asset centric approach, the specific benefits required from the statute can be calculated, restoration cost saving and impact to customers in terms of CMI, more accurately.

- **Comprehensive:** The comprehensive nature of the assessment is best practice, by considering and evaluating nearly the entire T&D system the results of the hardening plan provide confidence that portions of the TEC system are not overlooked for potential resilience benefit.
- **Consistency**: The model calculates benefits consistently for all projects. The model carefully normalizes for more accurate benefits calculation between asset types. For example, the model can compare a substation hardening project to an lateral undergrounding project. This is a

significant achievement allowing the assessment to perform project prioritization across the entire asset base for a range of budget scenarios. Without this capability, the assessment would not have been able to identify a point a diminishing returns, balance restoration and CMI benefits, and calculate benefits on the same basis for the entire plan.

- **Rooted in Cause of Failure:** The Storm Resilience Model is rooted in the causes of asset and system failure from two perspectives. Firstly, the Major Storms Event Database outlines the range of storm stressors and the high level impact to the system. Secondly, the detailed data streams and algorithms within the Storm Impact Model are aligned with how assets fail, mainly vegetation density, asset condition, wind zone, and flood modeling. With this basis, hardening investment identification and prioritization provides a robust assessment to focus investment on the portions of the system that are more likely to fail in the major storm.
- **Drives Prudency:** The assessment and modeling approach drive prudency for the Storm Protection Plan on two main levels. Firstly, the granularity of potential hardening projects, over 20,000,

allows TEC to invest in the portions of the system that provide the model value to customers. Without granularity, there is risk that parts of the system "ride the coat-tails" of needed investment causing efficient allocation of limited capital resources. Secondly, the budget optimization allows for the identification of the point of diminishing returns so that over investment in storm hardening is less likely.

- **Balanced:** Hardening projects include mitigation measures over all the four phases of resilience providing a diverse investment plan. Since storm events cannot be fully eliminated, the diversification allows TEC to provide a higher level of system resilience for customers.

Q50. What conclusions can be made from the results of the resilience analysis?

A50. The following include the conclusions of TEC's Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 13) shows the investment level is right before the point of diminishing returns. This provides confidence that TEC's plan does not over invest in storm hardening.

- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of \$0.61 to \$0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys. This reinforces that TEC's plan is prudent and making hardening investments that provide customer

benefits.

- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report. From a storm hardening perspective alone, the hardening investment types and overall level are prudent providing maximum value to customers. These 'blue sky' benefits just further enhance the business case for TEC customers

On the whole, TEC's storm hardening plan benefits assessment aligns with the requirements of the statue, shows prudency in the overall investment level and where hardening investment is focuses, provides maximum benefit to customers, and shows significant benefits to customers with a reasonable cost to buy down storm outages.

8. CONCLUSION

Q51. Does this conclude your prepared verified direct testimony?

A51. Yes.

(Whereupon, prefiled direct testimony of Jay W. Oliver was inserted.)

IN RE: PETITION FOR APPROVAL OF 2020-2029 STORM PROTECTION PLAN

BY DUKE ENERGY FLORIDA, LLC

FPSC DOCKET NO. 20200069-EI

DIRECT TESTIMONY OF JAY W. OLIVER

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Jay W. Oliver. My current business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Strategy and Asset Management Governance. DEBS is a wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy") that provides various administrative and other services to Duke Energy Florida, LLC ("DEF" or the "Company") and other affiliated companies of Duke Energy.

Q. What are your responsibilities as General Manager, Grid Strategy and Asset Management Governance?

A. My duties and responsibilities include planning for grid upgrades, system planning, and overall Distribution asset management strategy across Duke Energy.

Q. Please summarize your educational background and professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology and a Master's degree in Business Administration from the University of South Florida. I am a licensed Electrical Engineer and a registered Professional Engineer in Florida. From 30 years working in the electric utility business, I have experience in electric transmission, distribution, and information technology and telecommunications systems that support utility transmission and distribution networks. I began working at Duke Energy in 1996, joining one of its predecessor companies, Florida Progress. Over the past 10 years, I have held the positions of General Manager Grid Strategy and Asset Management Governance, General Manager Engineering and Technology, Director Distribution Services, Major Projects Manager, and Director, Grid Automation. I have been in my current role since January 2020.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. In 2019, the Florida Legislature enacted Section 366.96, Florida Statutes, which requires DEF to prepare and file a Storm Protection Plan ("SPP"). Specifically, "[e]ach plan 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." Section 366.96(3), Fla. Stat. (the "SPP Statute"). As directed by the SPP Statute, the Florida Public Service Commission ("the Commission" or "FPSC") enacted Rule 25-6.030, F.A.C. (the "SPP Rule"), which specifies the elements that must be included in each utility's SPP. My testimony explains the process that the Company used to evaluate various programs and projects that would meet the criteria set out in the SPP statute and rule. The result of that analysis is presented in the Company's SPP, which is attached to my testimony in five exhibits.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. __ (JWO-1), DEF 2020 Project-Level Detail;
- Exhibit No. __ (JWO-2), DEF SPP Plan Program Summaries:
- Exhibit No. __ (JWO-3), DEF SPP 3-year Investment Summary;
- Exhibit No. __ (JWO-4), DEF SPP Support; and
- Exhibit No. __(JWO-5), DEF Service Area.

These exhibits were prepared by the Company under my direction, and they are true and correct to the best of my information and belief. Mr. Thomas G. Foster is co-sponsoring Revenue Requirements and Rate Impacts of Exhibit No. __ (JWO-2).

Q. Please summarize your testimony.

A. My testimony presents the Company's SPP for the planning period 2020-2029. DEF's SPP is designed to cost-effectively "strengthen the Company's infrastructure to withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management" in accordance with the legislature's directive. Since the destruction caused by the active

2004/2005 hurricane season, at the Commission's direction, DEF has made great strides in strengthening its system to withstand the impacts of extreme weather events. The programs included in DEF's SPP build upon that foundation and present a holistic approach to further strengthening the Company's infrastructure with the goal of reducing outage frequency and duration during extreme weather events and enhancing overall reliability.

III. CURRENT STORM HARDENING PLAN AND GRID IMPROVEMENT PROJECTS AND OVERVIEW OF SPP.

Q. Please explain what projects DEF is currently implementing related to storm hardening.

A. In 2007 the Commission enacted Rule 25-6.0432, which is "intended to ensure the provision of safe, adequate, and reliable electric transmission and distribution service for operational as well as emergency purposes; require the cost-effective strengthening of critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions; and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions." To meet these objectives, investor-owned utilities like DEF are required to file a storm hardening plan every three years. The Commission approves each utility's storm hardening plan depending on whether the plan meets the intended objectives. DEF filed its last Storm Hardening Plan, for years 2019-2021, in March 2019, and the Commission approved it by order in July 2019. DEF's 2019-2021 Storm Hardening Plan includes initiatives that meet the objective of the storm hardening rule. Given the similarities between the storm hardening rule and the SPP Rule, a majority of DEF's current storm hardening activities will meet the objectives of the new SPP Rule and will continue, though many of these activities will be combined into new SPP Programs such as the Feeder and Lateral Hardening Programs.

Q. How has DEF's current Storm Hardening Plan impacted the development of the SPP?

A. The current Storm Hardening Plan (and its previous iterations) provided the foundation upon which the SPP builds. Indeed, because Year 1 of the SPP is 2020, the activities included in the Storm Hardening Plan for 2020 are already planned and in flight, DEF was unable to pivot and change course on those projects for 2020. Accordingly, DEF has summarized the activities in the Storm Hardening Plan that will carry over as projects for year 1 of the SPP, as required by the SPP Rule. Starting in year 2021 (or year 2 of the SPP), DEF will begin a transition to a more holistic system vision for hardening against extreme weather events and enhancing reliability. Additionally, the Storm Hardening Plan activities selected for the SPP provided a baseline of knowledge on which to base this more holistic system vision for hardening against extreme weather events.

Q. Does DEF have any other projects in flight related to SPP?

A. Yes, in the 2017 Settlement approved by the Commission,[1] DEF received a base rate increase for certain grid improvement projects, such as Targeted

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[1] Order No. PSC-2017-0451-AS-EU.

Undergrounding and Self-Optimizing Grid. Because these programs meet the criteria of SPP, in that they are expected to reduce extreme weather event cost and outage duration and improve overall reliability, DEF included those programs in the SPP.

Q. Please describe how the SPP is organized.

A. DEF's SPP is attached as five Exhibits. Exhibit No. __ (JWO-1) includes those activities in the Storm Hardening Plan or approved as part of the 2017 Settlement that will also be included in the SPP. Locations, unit counts, Capital and O&M costs by project are included, as well as the expected spend and unit counts for Years 1-3. This exhibit satisfies subsection (3)(e) of the SPP Rule. Exhibit No. __(JWO-2) provides summaries for all programs included in the SPP, associated justifications and benefits, unit counts, and projected spend for the first three years of the SPP. This exhibit satisfies subsection (3)(a), (3)(b), (3)(d), and (3)(f) of the SPP Rule. Exhibit No. __ (JWO-3) is DEF's 3-year Investment Summary across all SPP Programs. Exhibit No. __(JWO-4) includes a write-up of the program benefit and prioritization methodology. This exhibit provides information required by subsection (3)(d)5. of the SPP Rule. Exhibit No. _(JWO-5) includes a map of DEF's service area and an associated customer count as required by subsection (3)(c) of the SPP Rule. The remainder of my testimony will briefly summarize these sections, including the process by which DEF completed the analysis in each section. Mr. Foster's testimony will present the rate impact and revenue requirements as required by the SPP Rule.

Q. How did DEF approach the development of the SPP?

A. DEF recognized that the development of its first SPP pursuant to the SPP Statute and Rule would be an enormous, and important, undertaking. The work done in this first SPP will establish the framework for future SPP filings and analysis. As explained above, DEF was able to build off its existing Storm Hardening Plan and grid improvement projects, but it needed a robust method to gather data to drive the selection and prioritization of programs and evaluate benefits of each program. DEF thus initiated a Request for Proposals process to select a third-party contractor to provide modeling services and support for this analysis. As a result of this process, DEF selected Guidehouse[2] to provide modeling assistance. Guidehouse's team has a deep level of industry experience in the areas of Transmission and Distribution systems, climate resilience, risk mitigation, cost-benefit analyses, and predictive analytical techniques.

At the same time, DEF assembled a cross-functional team of Company experts from various business functions, including Distribution, Transmission, Vegetation Management, Geographic Information System ("GIS"), and associated systems to work collaboratively with Guidehouse to develop a plan of programs that will meet the requirements of the SPP Statute and Rule. Each element of the process is explained in greater detail below.

IV. OVERVIEW OF PROGRAMS EVALUATED IN THE SPP.

Q. How did DEF develop the list of programs for the SPP?

[2] Guidehouse LLP completed its acquisition of Navigant Consulting, Inc, in October 2019. The two brands are now combined as Guidehouse.

A. As explained above, DEF first started with its existing Storm Hardening Plan activities. From there, DEF consulted with subject matter experts with knowledge of DEF's Transmission and Distribution system and assets to identify additional potential programs and projects that would meet the requirements of the SPP Statute and Rule. DEF also met with other utilities to identify and validate potential programs.

An example of a new SPP program is the Feeder Hardening Program. The Feeder Hardening Program upgrades overhead Distribution facilities on main line circuits to meet extreme wind loading requirements as defined in NESC Code 250C, grade C (extreme wind loading). This program results in stronger poles, among other things, and meets the criteria of SPP in that it is expected to reduce outage times and cost in extreme weather conditions and improve overall service reliability. A complete list of the program names and descriptions can be found in my Exhibit No. __ (JWO-2).

Q. Are there other potential programs that DEF may consider in the future for inclusion in the SPP?

A. Yes, DEF will continue to monitor emergent technologies that may warrant further review and consideration.

V. PROGRAM EVALUATION, PRIORITIZATION, AND SELECTION

Q. Once the Company had a list of the programs, what was the next step of the analysis?

A. With the program list, Guidehouse then requested detailed data from the Company to evaluate each program from a risk and benefit standpoint. Specifically, the Company provided GIS data regarding the specific types of locations of various types of assets across DEF's service territory (e.g., distribution feeder lines and poles, substations, transmission structures, etc.). DEF also provided information on items like prior storm damage, vegetation management outage data, and historical data on existing storm hardening programs.

Q. Please provide an example of how a particular program was analyzed within the Guidehouse model.

A. Using the Feeder Hardening program as an example, Guidehouse estimated a reduction in storm damage and duration, using CMI as a proxy for duration. That model further enables us to prioritize the work over the life of the program based on highest benefit work first. As discussed in more detail in Exhibit No. __ (JWO-2), the Guidehouse model prioritized work by looking at the probability of damage to particular assets (including consideration of information from various FEMA-produced models) and the consequences of that damage, including for example the number and/or type of customers served by particular assets. That information was then evaluated by subject matter experts in the Distribution and Transmission functions for further analysis and prioritization.

Q. Please discuss how DEF prioritized 2020 projects in the SPP.

A. As discussed above, the Commission approved DEF's last Storm Hardening Plan in 2019. Implementation of that plan has already been in flight for 2020, so the SPP did not make any changes to that work.

Q. Please discuss how DEF selected its 2021 programs in the SPP.

A. We continue the SHP and multi-year rate plan (as described above) and will begin the transition to the new SPP Programs: for Distribution the Feeder Hardening Program and for Transmission the Structure Hardening Program. These Programs were selected based on the analysis described herein and more specifically in Exhibit No. __ (JWO-2).

Q. How did DEF identify programs and projects for the other years of the SPP?

A. For year three of the SPP (2022) and beyond, DEF developed long-term plans for the work that is needed to harden and strengthen the Distribution and Transmission infrastructure against extreme weather events and improve overall reliability. These are more fully described in Exhibit No. __ (JWO-2). DEF will use the methodology outlined in Exhibit No. __ (JWO-2) to identify and prioritize the work within these specific programs it plans to implement in 2022. For years four through ten of the SPP, DEF generally assumed that it would continue similar programs as what it identified in year three. In terms of identifying the total amount of work planned for those years, DEF applied general assumptions given the work completed in years one through three and DEF's ability to feasibly complete work each year. However, DEF expects that when it files its next SPP, it will be able to provide additional details about the amount and scope of work planned for years four through ten.

Q. Does DEF believe there are any implementation alternatives that could mitigate the resulting rate impact for each of the first three years of the proposed Storm Protection Plan?

A. DEF does not believe there are any implementation alternatives that could mitigate the resulting rate impact for the first three years of the SPP without causing a parallel reduction in the benefits the SPP is designed to produce. To further mitigate the rate impact would require reducing or delaying commencement of work under the SPP (to the extent of the desired rate mitigation) which would also delay the realization of the benefits the SPP is designed to create.

VI. BENEFITS THAT DEF'S SPP WILL BRING TO DEF'S CUSTOMERS

Q. What is DEF proposing as its 2020-2029 SPP?

A. DEF proposes to implement activities included in Exhibit No. __ (JWO-1) and Exhibit No. __ (JWO-2). DEF is confident that the activities included in this ten-year plan will strengthen its infrastructure, reduce outage times associated with extreme weather events, reduce restoration costs, and improve overall service reliability.

Q. Can you provide any additional detail about each program DEF is proposing to include in its SPP?

A. Yes, for ease of reference, DEF has prepared specific information for each program. Each program summary includes a detailed narrative description of the program, the benefit analysis for that program, and a summary table of annual projected spend for that program for the first three years, as well as the estimated total 10-Year spend. Each program summary is included in Exhibit No. __ (JWO-2).

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Thomas G. Foster was inserted.)

IN RE: REVIEW OF 2020-2029 STORM PROTECTION PLAN PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC

FPSC DOCKET NO. 20200069-EI

DIRECT TESTIMONY OF THOMAS G. FOSTER

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is Duke Energy Florida, LLC, 299 1st Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Director of Rates and Regulatory Planning.

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

A. I am responsible for the Company's regulatory planning and cost recovery, including the Company's Storm Protection Plan filing.

Q. Please describe your educational background and professional experience.

A. I joined the Company on October 31, 2005 in the Regulatory group. In 2012, following the merger with Duke Energy Corporation ("Duke Energy"), I was promoted to my current position. I have 6 years of experience related to the operation and maintenance of power plants obtained while serving in the United States Navy as a Nuclear Operator.

I received a Bachelors of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I received a Masters of Business Administration with a focus on finance from the University of South Florida and I am a Certified Public Accountant in the State of Florida.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an estimate of the annual revenue requirements for the Company's 2020-2029 Storm Protection Plan ("SPP"), as required by Rule 25-6.030(3)(g), F.A.C., as well as an estimate of rate impacts for each of the first three years of the SPP for DEF's typical residential, commercial, and industrial customers, as required by Rule 25-6.030(3)(h), F.A.C.

Q. Have you prepared, or caused to be prepared under your direction, supervision, or control, exhibits in this proceeding?

A. Yes. I am co-sponsoring the Revenue Requirements and Rate Impact section of Exhibit No. __ (JWO-2) attached to the direct testimony of Mr. Oliver. This section of Exhibit No. __ (JWO-2) is true and accurate to the best of my knowledge and belief.

Q.

What are the estimated annual revenue requirements for the Company's

A. **2020-2029 SPP?**

That information is found on page 40 of Exhibit No. __ (JWO-2).

Q. What are the estimated rate impacts for each of the first three years of the SPP for DEF's typical residential, commercial, and industrial customers?

A. That information is found on page 40 of Exhibit No. __ (JWO-2).

Q. Has DEF complied with the requirements of Rule 25-6.030(3)(g) and (3)(h)?

A. Yes.

Q. Does that conclude your testimony?

A. Yes.

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

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael Spoor, and my business address is One Energy Place, Pensacola, Florida, 32520.

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

A. I am employed by Gulf Power Company ("Gulf" or the "Company") as Vice President of Power Delivery.

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

A. As Vice President of Power Delivery, I am responsible for the planning, engineering, construction, operation, maintenance and restoration of Gulf's transmission and distribution ("T&D") grid. This includes the systems, processes, analyses, and standards utilized to ensure Gulf's T&D facilities are safe, reliable, secure, effectively managed and in compliance with regulatory requirements.

Q. Please describe your educational background and professional experience.

A. I graduated from Auburn University with a Bachelor of Science degree in Industrial Engineering and from Nova Southeastern University with a Master of Business Administration. I am also a graduate of executive education programs at both Columbia University and Kellogg School of Management at Northwestern University. I am a registered professional engineer in the State of Florida. I joined Florida Power & Light Company ("FPL") in 1985 and have served in a variety of leadership positions including area operations manager, manager of reliability, director of distribution system performance, director of business services and director of distribution operations. I assumed my current position and responsibilities in January 2019, having previously served as Vice President of Transmission and Substation with FPL.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and support Gulf Power's 2020-2029 Storm Protection Plan ("SPP"), attached as Exhibit MS-1, and demonstrate that Gulf's proposed SPP is in compliance with Section 366.96. Florida Statutes ("F.S.") and Rule 25-6.030, Florida Administrative Code ("FAC"). Specifically, my testimony provides a description of each storm protection program included in Gulf's SPP and how it is expected to reduce restoration costs and outage times, estimated start/completion dates, estimated costs, and criteria used to select and prioritize SPP projects. I will also provide project detail for the first three years in Gulf's proposed SPP.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibit: Exhibit MS-1 – Gulf Power's 2020-2029 Storm Protection Plan.

II. OVERVIEW OF GULF'S 2020-2029 SPP

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

A. On June 27, 2019, the Governor of Florida signed into law SB 796 titled, "Storm Protection Plan Cost Recovery", which was codified in Section 366.96, F.S. Therein, the Florida Legislature found that it was in the State's interest to "strengthen electric utility infrastructure to withstand extreme weather conditions by promoting the overhead hardening of distribution and transmission facilities, undergrounding of certain distribution lines, and vegetation management," and for each electric utility to "mitigate restoration costs and outage times to utility customers when developing transmission and distribution storm protection plans." See § 366.96(1). Based on these findings, the Florida Legislature directed each electric utility to file a SPP with the Florida Public Service Commission ("FPSC") covering the immediate 10-year planning period. See § 366.96(3). Consistent with this legislative requirement, Gulf is submitting its SPP for the ten-year period of 2020-2029.

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

Q. What programs are included in Gulf's proposed 2020-2029 SPP?

A. Gulf's proposed SPP is both a continuation and expansion of existing Commission-approved storm hardening and storm preparedness programs and includes one new program, Distribution Hardening - Lateral Undergrounding Program. The following programs comprise Gulf's SPP:

- Distribution Inspection Program
- Transmission Inspection Program
- Distribution Feeder Hardening Program
- Distribution Hardening – Lateral Undergrounding Program
- Transmission Hardening Program
- Vegetation Management – Distribution Program
- Vegetation Management – Transmission Program

With the exception of the new program to target and underground select distribution laterals, the majority of these programs have been in place since 2007. As demonstrated by recent storm events, these programs have been successful in reducing restoration costs and outage times following major storms, as well as improving day-to-day reliability. Gulf submits that continuing these existing Commission-approved storm hardening and storm preparedness programs in the SPP is appropriate and necessary to address the expectations of Gulf's customers and other stakeholders for increased storm resiliency and will result in fewer outages and prompt service restoration. The proposed SPP will continue to expand the benefits of hardening, including improved day-to-day reliability, to all customers throughout Gulf's system.

Q. What are the benefits of Gulf's 2020-2029 SPP Programs?

A. The major benefit of Gulf's proposed SPP is to provide resiliency and faster restoration to the electric infrastructure that our approximately 468,000 customers and Northwest Florida's economy rely on for their electricity needs. Safe and reliable electric service is essential to the life, health, and safety of the public, and has become a critical component of modern life. Florida remains the most hurricane-prone state in the nation and, with the significant coast-line exposure of Gulf's system and the fact that 50% of Gulf's customers live within 1 mile of a coast or major body of water, a robust SPP is critical to maintaining and improving grid resiliency and storm restoration as contemplated by the Legislature in Section 366.96.

Gulf's proposed SPP programs have already demonstrated that they have and will provide increased Transmission and Distribution ("T&D") infrastructure resiliency, reduced restoration time, and reduce restoration cost when Gulf is impacted by severe weather events. The eastern portion of Gulf's service area was recently impacted by

Hurricane Michael and demonstrated the damage incurred by non-storm hardened areas was significantly higher than those areas which were storm hardened.

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

Q. Does Gulf's 2020-2029 SPP address recovery of the costs associated with the proposed SPP?

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

III. DESCRIPTION OF EACH PROPOSED SPP PROGRAM

Q. Has Gulf provided the information required by Rule 25-6.030(3)(d), F.A.C. for each program included in its proposed 2020-2029 SPP?

A. Yes. In accordance with Rule 25-6.030(3)(d), F.A.C., Gulf's proposed SPP provides, if applicable: (1) a description of how each program is designed to enhance Gulf's existing transmission and distribution facilities including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions; (2) identification of the actual or estimated start and completion dates of the program; (3) a cost estimate including capital and operating expenses; (4) a comparison of the costs and the benefits;

and (5) a description of the criteria used to select and prioritize proposed storm protection programs. Each of the above listed descriptions is provided in Section IV of Gulf's proposed SPP. Below, I will provide a brief overview of each program included in Gulf's proposed SPP.

Q. Please provide a summary of Gulf's Distribution Inspection Program under the SPP.

A. Gulf's Distribution Inspection Program is a continuation of Gulf's existing Commission-approved distribution inspections which consists of feeder patrols, infrared patrols, and wood pole inspections. These programs exist to ensure a more storm resilient distribution infrastructure which will result in reductions in wood pole failures, fewer storm-related outages, and reduction in storm restoration time and costs.

The total estimated costs of the Distribution Inspection Program are $37.5 million with an annual cost of approximately $3.7 million.[1] Annually, Gulf inspects approximately 770 miles of mainline feeders and 4,100 pieces of equipment. With approximately 208,000 distribution wood poles as of year-end 2019, Gulf expects to inspect approximately 26,000 wood poles annually during the 2020-2029 SPP period.

A detailed explanation of the Distribution Inspection Program, its costs and benefits, is contained in Gulf's SPP, Section IV(A), Distribution Inspection Program.

Q. Please provide a summary of Gulf's Transmission Inspection Program under the SPP.

A. Gulf's Transmission Inspection Program will continue its existing Commission-approved inspection program consisting of substations and structures. Gulf's annual inspections of

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

transmission substations follow a prescribed set of processes and procedures utilized by Company personnel, to inspect substation equipment annually. These inspections are performed on substation equipment such as: batteries and chargers, breakers, instrument transformers, power fuses, regulators, substation yard, switches, and transformers.

The proposed SPP includes continuing aerial patrols to inspect transmission lines and circuits. Gulf's transmission structure inspection program is based on two alternating twelve year cycles, which results in a structure being inspected at least every six years. As explained in the proposed SPP, the performance of Gulf's transmission facilities during recent storm events indicates Gulf's Transmission Inspection Program has contributed to the overall storm resiliency of the transmission system and provided storm restoration savings in both time and costs.

The total estimated costs for the Transmission Inspection Program for the ten-year period of 2020-2029 is $35 million with an annual average cost of approximately $3.5 million, which is consistent with historical costs for the existing Transmission Inspection Program.[2]

A detailed description of the Transmission Inspection Program is provided in Section IV(B) of Gulf's proposed SPP.

Q. Please provide a summary of Gulf's Distribution Feeder Hardening Program under the SPP.

A. In Gulf's 2019-2021 Storm Hardening Plan, submitted to the Commission on March 1, 2019, Gulf introduced a new program to storm harden its distribution feeders to higher National Electric Safety Code storm hardening construction or Extreme Wind Loading ("EWL") standards. During 2006-2018, Gulf reconstructed many existing feeders, most of them considered Critical Infrastructure Function feeders which serve hospitals, police

[2] *See* footnote 1.

and fire stations, water treatment facilities, and feeders that serve other key community needs. In 2019, Gulf began to apply EWL standards to the design and construction of all new pole lines and major planned work, including pole line extensions and relocations, and certain pole replacements. This new construction standard for Gulf improves its distribution storm resiliency and overall service reliability to its customers.

Gulf has approximately 269 feeders remaining to be hardened and expects to harden approximately 12 to 18 feeders annually, with approximately 50% of Gulf's feeders to be hardened or underground by year-end 2029. The total estimated costs for the Distribution Feeder Hardening Program for the period of 2020-2022 is approximately $87.1 million with an annual average cost of $29 million. The total estimated costs for the period of 2020-2029 is $315.3 million with an annual average cost of $31.5 million.[3]

A detailed explanation of the program, its costs and benefits, is contained in Gulf's SPP, Section IV(C), Distribution Feeder Hardening Program.

Q. Please provide a summary of Gulf's Distribution Hardening – Lateral Undergrounding Program under the SPP.

A. Gulf is proposing in its SPP to initiate a new lateral undergrounding program, similar to that conducted by FPL and Duke Energy Florida. The program would build upon the experiences of FPL and focus on targeting certain overhead laterals, i.e., overhead laterals impacted by recent storms and with a history of vegetation-related outages and other reliability issues, spread throughout Gulf's system. Key objectives of the initial program would include validating conversion costs and identifying cost savings opportunities, testing different design philosophies, better understanding customer impacts and sentiments, and identifying barriers (e.g., obtaining easements, locating transformers, and attaching entities' issues). The evaluation and engineering of Gulf's lateral identified to be

[3] *See* footnote 1.

converted from overhead to underground will begin during the fourth quarter of 2020. Gulf will begin construction in 2021 of its lateral underground program and for the period of 2021-2022, costs are estimated at approximately $10.4 million with an annual average cost of approximately $5.2 million. The total estimated costs for the period of 2020-2029 is approximately $46.6 million with an annual average cost of approximately $4.7 million.[4]

A detailed explanation of the program, its costs and benefits, is contained in Gulf's SPP, Section IV(D), Distribution Hardening – Lateral Undergrounding Program.

Q. Please provide a summary of Gulf's Transmission Hardening Program under the SPP.

A. Based on Gulf's recent storm experience with Hurricane Michael, transmission hardening opportunities were identified in order to strengthen these critical facilities for the future. These are: substation flood monitoring and hardening, transmission and substation resiliency, and transmission structure replacement.

Beginning in 2019, Gulf began a substation hardening program by implementing flood monitoring on vulnerable substations and reviewing switch house construction standards for possible replacement and strengthening. Gulf is re-evaluating substation locations using the Coastal Substation Risk Assessments for all substations. As part of this process, a National Oceanic and Atmospheric Administration Sea, Lake and Overland Surges from Hurricanes ("SLOSH") model is being used to define the potential maximum flood levels. SLOSH is a computerized model run by the National Hurricane Center to estimate storm surge heights and winds resulting from historical, hypothetical, or predicted hurricanes. Gulf will implement flood monitoring on vulnerable substations and review switch house construction standards for possible replacement and strengthening.

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[4] *See* footnote 1.

While Gulf's transmission and substation facilities have continued to perform satisfactorily in the past, it should be noted that Gulf's system and the reliability has been impacted by single point of failure events that have had, and will continue to have, the potential to greatly impact customers. Gulf has initiated a transmission and substation resiliency program and has begun to invest in the overall strengthening of the electric grid at the transmission and substation level to remove these critical single points of failure that have the potential to impact large numbers of customers for extended periods of time. By building redundancy in the system to make it more resilient, these improvements will eliminate outages, and shorten restoration times following major weather events.

In Gulf's 2019-2021 Storm Hardening Plan, submitted to the Commission on March 1, 2019, Gulf introduced a new program to storm harden its transmission wood structures by replacing them with steel or concrete structures. As of year-end 2019, 62% of Gulf's transmission structures, system-wide, were steel or concrete, with approximately 38% (approximately 4,600) wood structures remaining to be replaced. Gulf expects to replace the approximately 4,600 wood transmission structures remaining on its system by year-end 2029. The total estimated costs for the Transmission Hardening Program for the ten-year period of 2020-2029 are $488.8 million with an annual average cost of approximately $48.9 million.[5]

A detailed explanation of the program, its costs and benefits, is contained in Gulf's SPP, Section IV(E), Transmission Hardening Program.

Q. Please provide a summary of Gulf's Vegetation Management – Distribution Program under the SPP.

A. Gulf proposes to continue its existing Commission-approved Vegetation Management - Distribution Program which includes its system-wide: three-year cycle for feeders; mid-

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[5] *See* footnote 1.

year cycle inspection and trimming for feeders; four-year cycle for laterals; and continued education of customers through its Right Tree Right Place Program. On average, Gulf plans to inspect and trim annually approximately one-third (1/3) of its overhead feeder miles, or 259 miles; approximately one-fourth (1/4) of its overhead lateral miles, or 1,257 miles; and mid-cycle inspection and trim of approximately 518 miles for a total estimated inspection and trim average of approximately 2,000 miles per year. The primary objective of Gulf's Vegetation Management – Distribution Program is to clear vegetation in areas where Gulf is permitted to trim for the vicinity of distribution facilities and equipment in order to provide safe, reliable and cost-effective electric service to its customers. Additionally, as explained in the proposed SPP, recent storm events demonstrate that Gulf's existing Vegetation Management – Distribution Program has contributed to the overall improvement in the resiliency of distribution system during storms, resulting in reductions in storm damage to poles, days to restore, and storm restoration costs. The total estimated costs for the Vegetation Management – Distribution Program for the ten-year period of 2020-2029 is $47.4 million with an annual average cost of $4.7 million, which is consistent with historical costs for the existing Vegetation Management – Distribution Program.[6]

A more detailed explanation of the program, its costs and benefits, is contained in Gulf's SPP, Section IV(F), Vegetation Management – Distribution Program.

Q. Please provide a summary of Gulf's Vegetation Management - Transmission Program under the SPP.

A. Gulf proposes to continue its existing Commission-approved Vegetation Management – Transmission Program. This program also complies with the North American Electric Reliability Corporation's ("NERC") vegetation management standards and requirements

[6] *See* footnote 1.

for Gulf's transmission system. The reliability objective of these standards and requirements is to prevent vegetation-related outages which could lead to cascading by utilizing effective vegetation maintenance. Approximately just over one third of Gulf's total transmission system, or approximately 600 miles, fall under the NERC vegetation management standards and requirements. The key elements of Gulf's Vegetation Management – Transmission Program are rights of way ground floor vegetation management, annual ground inspections of transmission rights of way, document vegetation inspection results and findings, and prescribe a work plan and execute the work plan. For those transmission lines which fall under NERC's vegetation management standards and requirements, Gulf plans to pilot and begin using a technology called LiDAR, Light Detection and Ranging. The collected LiDAR data will be used to develop preventative and reactive work plans. Gulf will continue to develop and execute annual work plans to address identified vegetation conditions. Under the proposed SPP, Gulf plans to continue its current program of identifying and correcting priority vegetation and hazard tree conditions. The total estimated costs for the Vegetation Management – Transmission Program for the ten-year period of 2020-2029 is $28.3 million with an annual average cost of approximately $2.8 million, which is consistent with historical costs for the existing Vegetation Management – Transmission Program.[7]

A more detailed explanation of the program, its costs and benefits, is contained in Gulf's SPP, Section IV(G), Vegetation Management – Transmission Program.

IV. <u>ADDITIONAL DETAILS FOR FIRST THREE YEARS OF THE SPP</u>

Q. Has Gulf provided additional details and information for the first year of the proposed 2020-2029 SPP?

[7] *See* footnote 1.

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

Q. Does Gulf's proposed 2020-2029 SPP provide project related information for the second and third years of the SPP in sufficient detail to develop preliminary estimates of rate impacts?

A. Yes. As required by Rule 25-6.030(3)(e)(2), F.A.C., for the second and third years (2021-2022) of the SPP, Gulf has provided the estimated number and costs of projects under each specific SPP program. This information is provided in Appendix C to Gulf's SPP.

Q. Did Gulf provide a description of its vegetation management activities under the proposed 2020-2029 SPP for the first three years of the SPP?

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

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

A. Yes. Pursuant to Rule 25-6.030(3)(g), F.A.C., Gulf has provided the estimated annual jurisdictional revenue requirements in Section VI of the SPP. While Gulf has provided estimated costs by program as of the time of this filing and associated total revenue requirements in its SPP, consistent with the requirements of Rule 25-6.030, F.A.C., subsequent projected and actual program costs submitted for cost recovery through the Storm Protection Plan Cost Recovery Clause (per Rule 25-6.031, F.A.C.,) could vary by as much as 10-15%, which would then also impact associated estimated revenue requirements and rate impacts. The projected costs, estimated costs, actuals costs, and true-up of actual costs to be included in Gulf's Storm Protection Plan Cost Recovery Clause will all be addressed in subsequent filings in separate Storm Protection Plan Cost Recovery Clause dockets pursuant to Rule 25-6.031, F.A.C.[8]

Q. Has Gulf estimated the rate impacts for each of the first three years of the proposed 2020-2029 SPP?

A. Gulf anticipates the programs included in the SPP will have zero bill impacts on customer bills during the first year of the SPP and only minimal bill increases for years two and three of the SPP. An estimate of hypothetical overall rate impacts for the first three years of the SPP (2020-2022) based on the total program costs reflected in this filing, without regard for the fact that pursuant to a Commission-approved settlement agreement, Gulf remains under a general base rate freeze until base rates are next established by the Commission, are provided in Section VII of the SPP. The projected costs, estimated costs, actuals costs, and true-up of actual costs to be included in Gulf's Storm Protection Plan Cost Recovery

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

Clause will all be addressed in subsequent filings in separate storm protection plan cost recovery clause dockets pursuant to Rule 25-6.031, F.A.C.[9]

V. CONCLUSION

Q. Does Gulf believe that its proposed 2020-2029 SPP will achieve legislative objectives of Section 366.96, F.S., of reducing restoration costs and outage times associated with extreme weather events by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management?

A. Yes, while no electrical system can be made completely resistant to the impacts of hurricanes and other extreme weather conditions, the programs included in Gulf's SPP have already demonstrated that they mitigate and will continue to mitigate the impacts of future storms. Gulf's SPP is a systematic approach to achieve the legislative objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. As explained above and in further detail in the SPP, Gulf's SPP is largely a continuation and expansion of its existing Commission-approved storm hardening and storm preparedness programs. Continuing these previously approved and well-tested storm hardening and storm preparedness plans and initiatives under Gulf's SPP is critical to further mitigate restoration costs and outage times, continue to provide safe and reliable electric service to customers, and meet the needs and expectations of our customers, today and for many years to come.

Q. Does this conclude your direct testimony?

A. Yes.

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[9] *See* footnote 8.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 13th day of August, 2020.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC