BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20220048-EI

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

DOCKET NO. 20220049-EI

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

DOCKET NO. 20220050-EI

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

DOCKET NO. 20220051-EI

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

VOLUME 3
PAGES 379 - 596

PROCEEDINGS: HEARING

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

DATE: Wednesday, August 3, 2022

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

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

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

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMITTED
10	As identified in the CEL		516
11	As identified in the CEL		595

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

CHAIRMAN FAY: All right. I have 1:45 p.m. We will get started back. We will be taking up TECO's next witness.

You are recognized, Mr. Means.

MR. MEANS: Thank you, Mr. Chairman.

We call Jason DeStigter to the stand, and he is already up there.

Whereupon,

JASON DeSTIGTER

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

EXAMINATION

BY MR. MEANS:

Q Mr. DeStigter, could you please introduce yourself to the Commission?

CHAIRMAN FAY: Turn your mic on, Mr. DeStigter.

THE WITNESS: Jason DeStigter. Business address 9400 Ward Parkway, Kansas City, Missouri, 64114.

BY MR. MEANS:

Q And were you previously sworn?
A Yes, I was.
Q Who is your current employer?
A My current employer is 1898 & Company, a division of Burns & McDonnell.
Q And did you prepare and cause to be filed in this docket on April 11th, 2022, prepared direct testimony consisting of 73 pages?
A Yes.
Q And do you have any corrections to your testimony?
A I believe corrections were filed on July 13. No other corrections are needed.
Q If I were to ask you the questions contained in your prepared direct testimony today, would your answers be the same except for those changes we just discussed?
A Yes, sir.
MR. MEANS: Mr. Chairman, we would ask that his prepared direct testimony be entered into the record as though read.
CHAIRMAN FAY: Show it entered.
(Whereupon, prefiled direct testimony of Jason D. DeStigter was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220048-EI

TAMPA ELECTRIC's STORM PROTECTION PLAN

VERIFIED DIRECT TESTIMONY

OF

JASON D. DE STIGTER

ON BEHALF OF

TAMPA ELECTRIC COMPANY

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. A2. I am employed by 1898 & Co. as a Director and I lead the Utility Investment 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 250 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 8,300 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 College, now called 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 14 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 multi-billion-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 ("Tampa Electric").

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

A5. Yes, I provided written and rebuttal testimony on behalf of Tampa Electric Company for the 2020-2029 Storm Protection Plan before the Florida Public Service Commission, docket no 20200067-EI. I have also provided written, rebuttal, and oral testimony on behalf of Indianapolis Power & Light before the Indiana Utility Regulatory Commission and written testimony on behalf of Oklahoma Gas and Electric. Additionally, I 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 developed using 1898 & Co.'s 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 an overall investment level that maximizes customers' benefit while not exceeding Tampa Electric's technical execution constraints.

Through my testimony I will describe the major elements of the Storm Resilience Model, which includes 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 events to impact Tampa Electric's 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. Additionally, I will outline the key updates to the Storm Resilience Model for the 2022-2031 Storm Protection Plan. 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 2022-2031 Storm Protection Plan Resilience Benefits Report that is being included as Appendix F in Tampa Electric's 2022-2031 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 director on Tampa Electric's 2022-2031 Storm Protection Plan Assessments and Benefits Assessment. The evaluation utilized a Storm Resilience Model to calculate benefits. I worked directly with Tampa Electric's 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

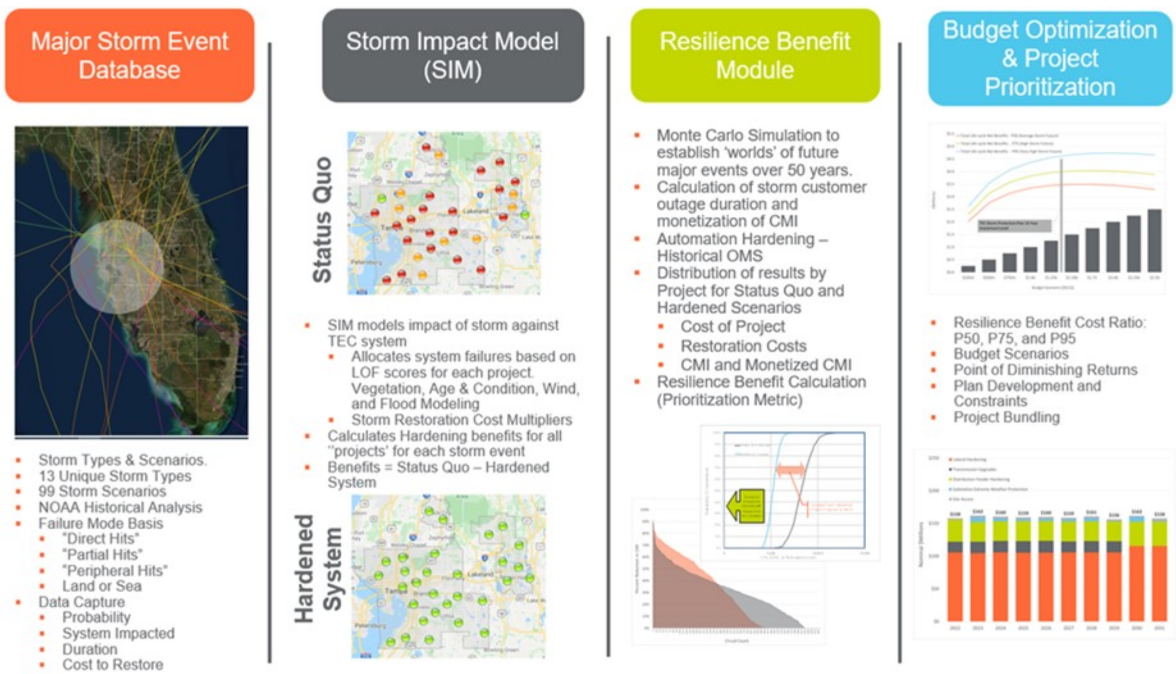
Q11. Please describe the analysis 1898 & Co. conducted for Tampa Electric.

A11. 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in Tampa Electric's 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 1 below provides an overview of the Storm Resilience Model used to calculate the project benefit and prioritize projects.

Figure 1: Storm Resilience Model Overview



The storms database includes the future 'universe' of potential storm events to impact Tampa Electric's 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. 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 Tampa Electric'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 of storm events to impact Tampa Electric's 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 Tampa Electric's technical and operational realities (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 "biggest bang for the buck."

Q12. Which of the Storm Protection Plan programs are evaluated within the Storm Resilience Model?

A12. 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

Q13. Please outline the key updates that were made to the Storm Resilience Model from the 2020-2029 to the 2022-2031 Storm Protection Plan assessment.

A13. The Storm Resilience Model was used in the development of the 2020-2029 Storm Protection Plan as well as the 2022-2031 Storm Protection Plan. The following are the key updates from the 2020-2029 to the 2022-2031 Storm Resilience Model:

1. **General** – these updates include shifting of the time horizon, adding another year of storms to the historical analysis, and accounting for completed projects.
2. **Capital Cost Assumptions** – based on actual completed projects and communicated increases in commodity prices the cost assumptions for all project types were adjusted.
3. **Substation Projects Development** – Tampa Electric

completed a technical evaluation of substation hardening alternatives since the 2020-2029 Storm Protection Plan filing. The results of that evaluation, including specific substation hardening activities and their cost were included in the model.

4. **Site Access Project Development** – Tampa Electric performed additional evaluation of transmission site access and updated the projects and associated costs.

5. **Automation Hardening Capital Costs** – 1898 & Co. performed detailed analysis on 300 circuits to identify more specific scope and cost. Based on lessons learned from the 2020 projects, the cost to deploy automation had a wide range given the uncertainty in circuit reconductoring and substation upgrades needed to not overload and burn down circuits. With improved cost estimates for the 300 circuits the prioritization of projects in the Storm Resilience Model is improved. This increases the overall benefit by decreasing major outage events for customers.

6. **Lateral Undergrounding 'Branching' Approach** – Based on a lessons learned evaluation, the project definition for lateral projects was adjusted to

include a collection of electrically connected protection zones, or 'branches'. Tampa Electric's undergrounding design standard includes looping for added resilience. Based on the 2020 project execution, it was identified that some of the projects included higher costs to achieve the full loop. By undergrounding all the electrically connected protection zones off a circuit feeder / mainline the higher costs will be mitigated since it can be designed more thoughtfully to minimize the number of new underground miles.

Q14. How is resilience defined?

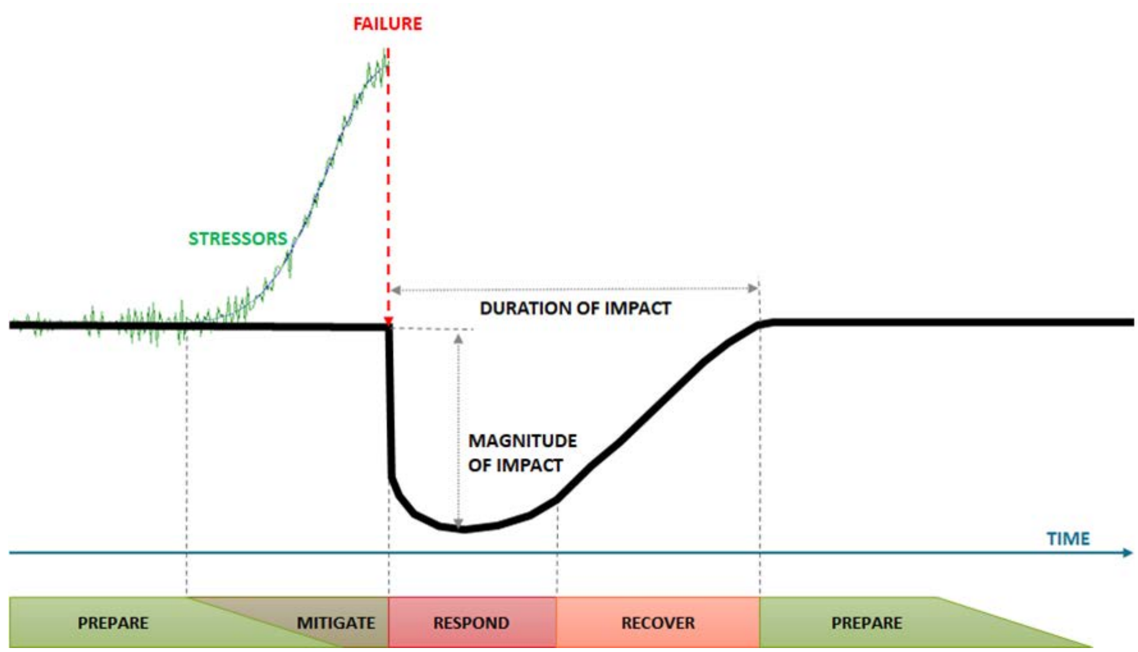
A14. There are many definitions for resilience, I gravitate to the one used by the National Infrastructure Advisory Council ("NIAC"). Their definition of resilience is: "The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise 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 2 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 2: Phases of Resilience



Q15. How does the Storm Resilience Model incorporate this definition?

A15. 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 Tampa Electric 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 Tampa Electric 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 the magnitude and duration of a storm event on a distribution circuit given its current state and after it has been hardened.

Q16. Please outline the type and count of hardening projects evaluated in the Storm Resilience Model.

A16. Table 1 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	12,310
Transmission Asset Upgrades	107
Substation Extreme Weather Hardening	9
Distribution Overhead Feeder Hardening	1,385
Transmission Access Enhancements	44
Total	13,855

Q17. How were these potential hardening projects identified?

A17. The potential hardening projects were identified based on a combination of data driven assessments, field inspection of the system, and historical performance of Tampa Electric'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 below shows the asset types and counts included in the Storm Resilience Model used to develop hardening projects.

Table 2: Tampa Electric's Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**710**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,300
Lateral OH Primary	[miles]	3,900
Transmission Circuits	**[count]**	**215**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	**[count]**	**9**
Site Access	**[count]**	**44**
Roads	[count]	25
Bridges	[count]	19

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 '1' 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 impacts from vegetation outside the 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 the 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 replacement 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.

Tampa Electric identified 44 separate transmission access, road, and bridge projects based on field inspections of the system.

Tampa Electric 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. Based on Tampa Electric's more detailed assessment, nine (9) substations were identified that included flooding risk to the level that could require mitigation.

Q18. Why is this approach to hardening project identification important?

A18. 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 of Tampa Electric’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 Tampa Electric’s 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 Tampa Electric 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 that come off a feeder and the Storm Resilience Model may determine that only 3 out of the 10 should be hardened. Without this granularity, over-investment in hardening is a concern. The adopted approach provides confidence that the overall plan is investing in the 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 Tampa Electric to provide a higher level of system resilience.

5. The approach balances the use of robust data sets with Tampa Electric's 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.

Q19. Why is it necessary to model storm hardening projects benefits using this resilience-based planning approach and Storm Resilience Model?

A19. 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 Tampa Electric’s service territory. Different storms have dramatically different impact to Tampa Electric’s system, for instance, in review of Tampa Electric’s historical storm reports, it was observed that tropical storm events even 100 to 150 miles away from Tampa Electric’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 Tampa Electric’s service territory. For this reason, the resilience-based planning approach includes the ‘universe’ of potential major events that could impact Tampa Electric over the next 50 years, this is the Major Storms Event Database. In relation to the conceptual model showing the phases of resilience (Figure 2), 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 2, 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 Tampa Electric's 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 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 Tampa Electric's technical constraints. I outline this in more detail below.

3. MAJOR STORMS EVENT DATABASE

Q20. Please provide an overview of the Major Storms Event Database and how it was developed.

A20. The Major Storms Event Database includes the 'universe' of storm events that could impact Tampa Electric's service territory over the next 50 years. The database describes the phases of resilience (Figure 2) for Tampa Electric's high-level system perspective for a range of storm stressors. It was developed collaboratively between Tampa Electric and 1898 & Co. It utilizes information from the National Oceanic and Atmospheric Administration ("NOAA") database of major storm events, Tampa Electric's historical storm reports, available information on the impact of major storms to other utilities, and Tampa Electric's experience in storm recovery. From that information, 13 unique storm types were observed to impact Tampa Electric's 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 Tampa Electric's service territory. Table 3 below 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 (Percent)	Restoration Costs (Millions)	System Impact (Laterals) (Percent)	Total Duration (Days)
1	Cat 3 Direct Hit-Gulf	1.0 - 2.0	306.0 - 1,224.0	60.0 - 70.0	17.4 - 34.5
2	Cat 1&2 Direct Hit-Florida	5.0 - 8.0	76.5 - 153.0	35.0 - 55.0	6.0 - 8.8
3	Cat 1&2 Direct Hit-Gulf	2.0 - 4.0	153.0 - 306.0	45.0 - 60.0	8.7 - 12.9
4	TS Direct Hit	16.5	25.5 - 76.5	12.5 - 31.3	2.6 - 5.3
5	TD Direct Hit	14.5	5.1 - 15.3	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	3.0 - 4.0	91.8 - 184.0	36.0 - 48.0	6.4 - 9.2
8	Cat 1&2 Partial hit	7.0	15.3 - 91.8	8.5 - 28.0	2.3 - 6.9
9	TS Partial Hit	17.0 - 18.0	11.5 - 30.6	8.0 - 15.0	2.0 - 3.6
10	TD Partial Hit	12.0 - 15.0	0.4 - 3.1	2.0 - 3.8	1.5 - 2.7
11	Cat 3 Peripheral Hit	2.0 - 3.0	0.8 - 22.2	1.2 - 14.1	1.0 - 3.0
12	Cat 1&2 Peripheral Hit	10.0 - 11.0	0.6 - 8.9	0.9 - 6.5	0.9 - 2.3
13	TS Peripheral Hit	11.0 - 12.0	0.5 - 3.8	0.7 - 3.4	0.9 - 1.3

Q21. What does the NOAA data show on the number and types of major storm events to impact Tampa Electric's service territory?

A21. The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 169 years, beginning in 1852. The NOAA major events database was mined for all major event types up to 150 miles from Tampa Electric's 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 Tampa Electric's service territory. Additionally, the database was mined for the category of the storm as it hit Tampa Electric's 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 Tampa Electric's 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 Tampa Electric's 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 below includes the summary results from the NOAA database of storms to hit or nearly hit Tampa Electric's 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	12	20	32	30	29	91
Tropical Depression	10	8	18	17	N/A	35
Total	32	37	69	68	50	187

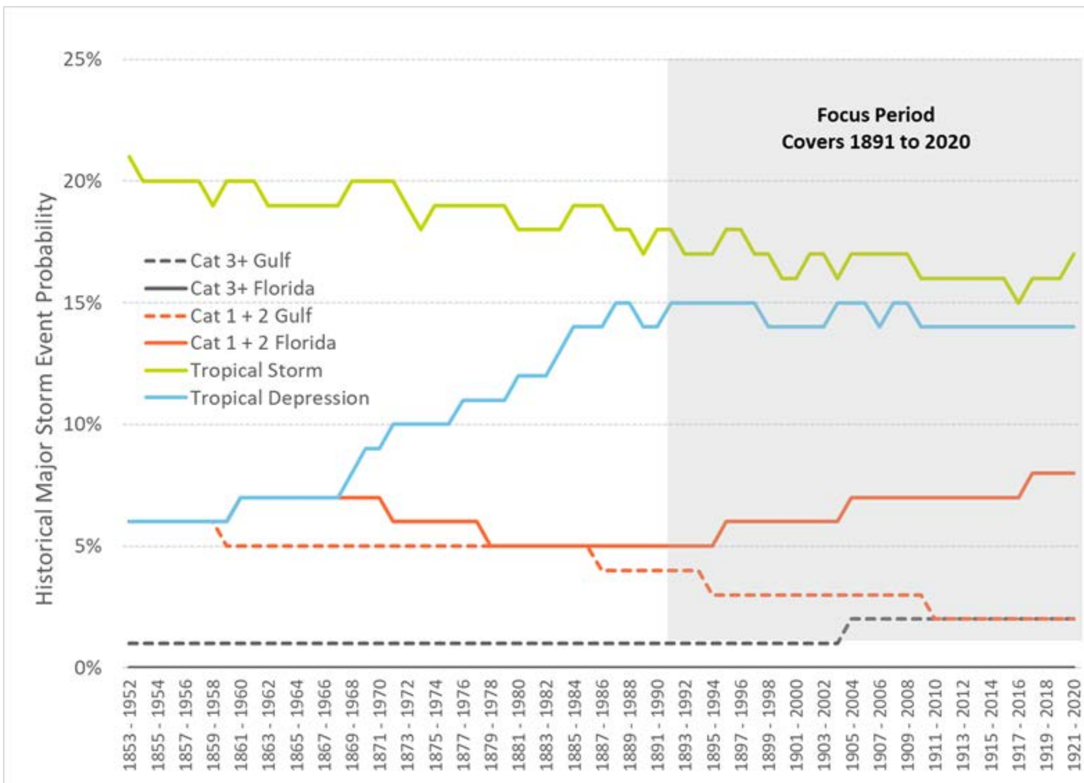
Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Table 4 shows a total of 187 storms to hit the Tampa area since 1852. A total of 69 were direct hits within 50 miles, 68 were partial hits in the 51 to 100-mile radius, and 50 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 187, with one 'Direct Hit'. While there are 10 Category 3 type 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.

Q22. What analysis of this historical storm information was done to determine the storm probability ranges?

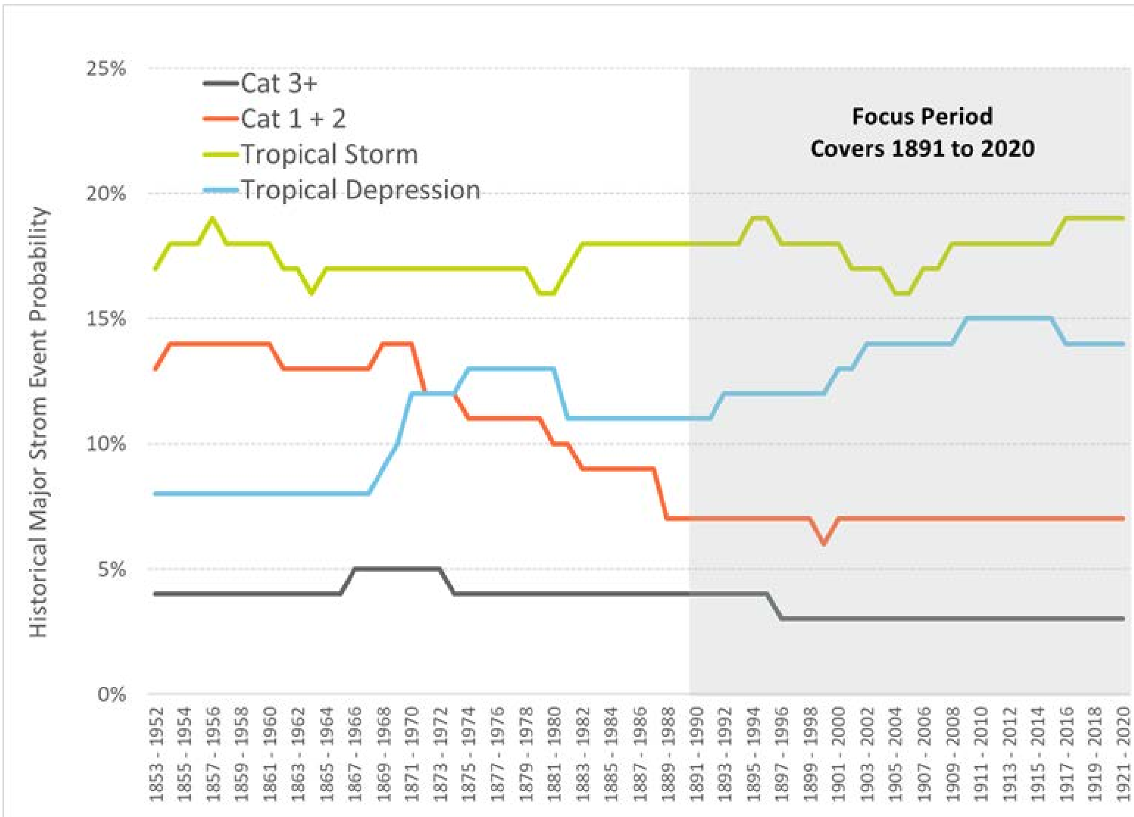
A22. 1898 & Co. converted the storm information from Table 4 above to show the total storm count for 100-year rolling average starting with the period of 1852 to 1951 ending with the period 1920 to 2020. This provides 70 distinct 100 year periods. This was done for each of the 13 unique storm events. 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



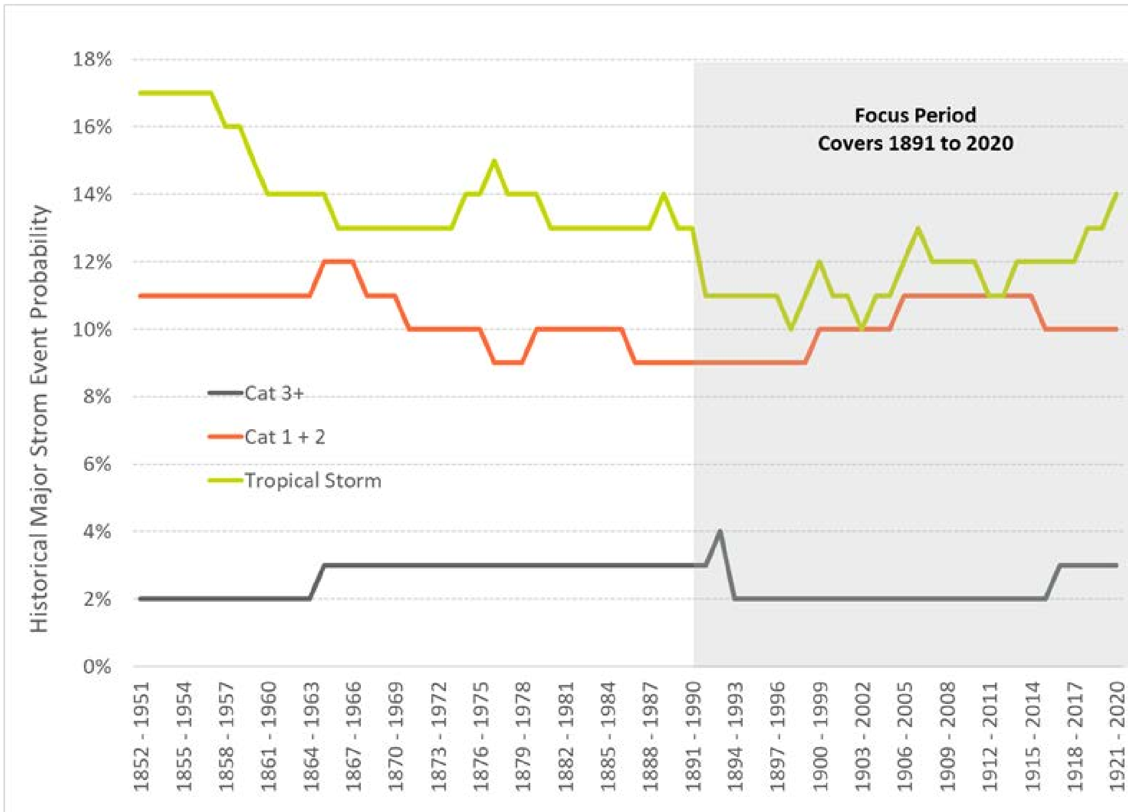
Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

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 2020. This time horizon served as the basis for developing the probability ranges for the 13 unique storm events.

Q23. How were the storm impact ranges developed?

A23. The range of system impacts for each storm scenario were developed based on historical storm reports from Tampa Electric and augmented by Tampa Electric's team experience with historical storm events. The database includes events that have not recently impacted Tampa Electric'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

Q24. Please provide an overview of the Storm Impact Model.

A24. The Storm Impact Model describes the phases of resilience, Figure 2, for each potential hardening project on Tampa Electric's 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.

Q25. 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.

A25. 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. Tampa Electric'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 Count/Customer Type.

GIS - The GIS provides the list of assets in Tampa

Electric'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 20 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 Tampa Electric's system. The customer information is used within the Storm Impact Model to calculate each storm's 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 Tampa Electric. 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 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 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 Tampa Electric's 255 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. Tampa Electric performed a more detailed assessment of the 59 substation and identified nine (9) for hardening improvement.

Q26. What were the results of the vegetation density algorithm?

A26. Figure 6 and Figure 7 below show the range of vegetation density for overhead ("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 Primary Conductor

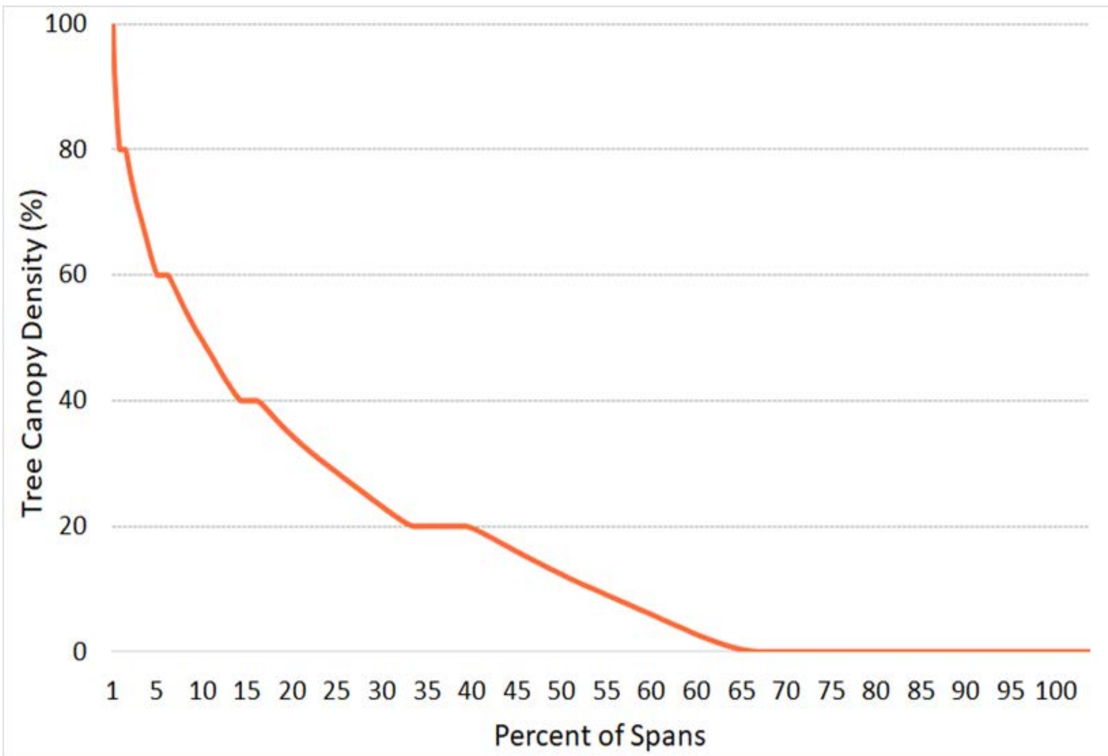
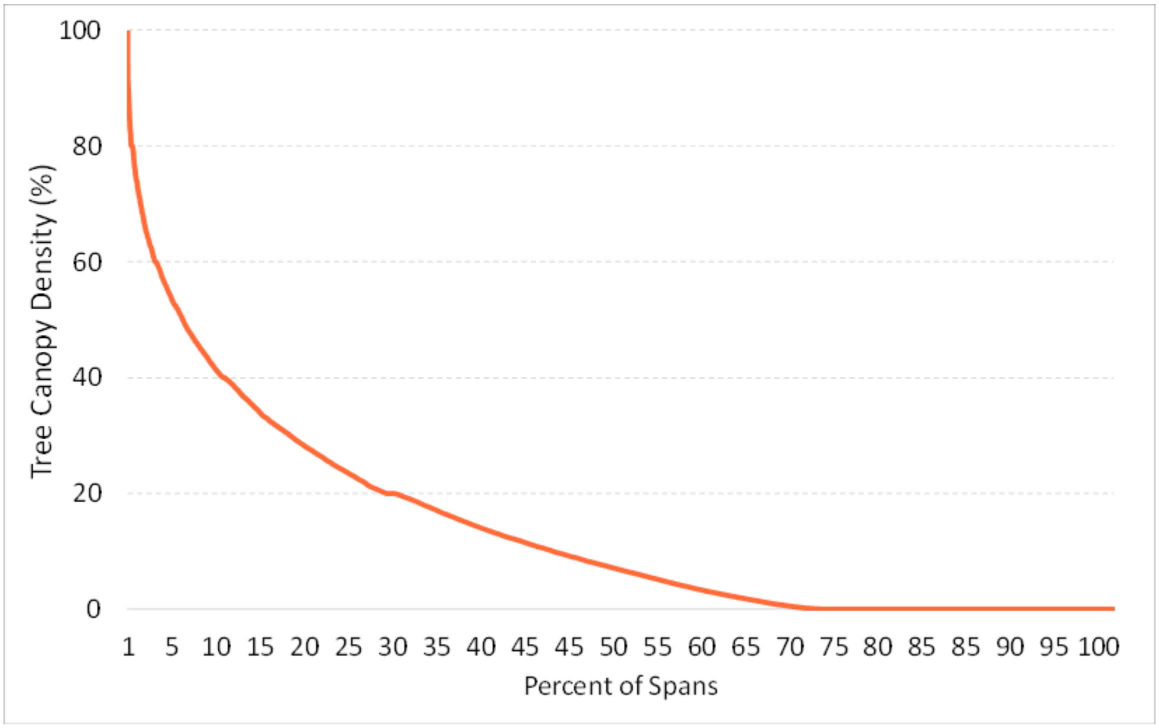


Figure 7: Vegetation Density on Transmission Conductor



Q27. How are asset and system failures during major storm events identified in the Storm Impact Model hardening projects?

A27. 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 circuits 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.

Q28. How are restoration costs allocated to the asset base for each major storm events?

A28. 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 Tampa Electric 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 Storms Event Database.

Q29. How are customer outage durations calculated in the model for each major storm event?

A29. 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.

Q30. Why were CMI benefits monetized?

A30. 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.

Q31. How was the CMI benefit monetized?

A31. 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.

Q32. How are the storm specific resilience benefits calculated for each project by major storm event?

A32. 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

Q33. Please provide an overview of the Resilience Benefit Calculation Module

A33. 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 OMS includes 20 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

Q34. What economic assumptions are used in the life-cycle Resilience Benefit Module?

A34. 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.
- Two (2) percent escalation rate
- Six (6) percent discount rate

Q35. How were hardening project costs determined?

A35. Project costs were estimated for approximately 14,000 projects in the Storm Resilience Model. Some of the project costs were provided by Tampa Electric 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.

Tampa Electric 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. Tampa Electric 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 a report done by a third-party for Tampa Electric to evaluate substation hardening initiatives, such as raising control houses.

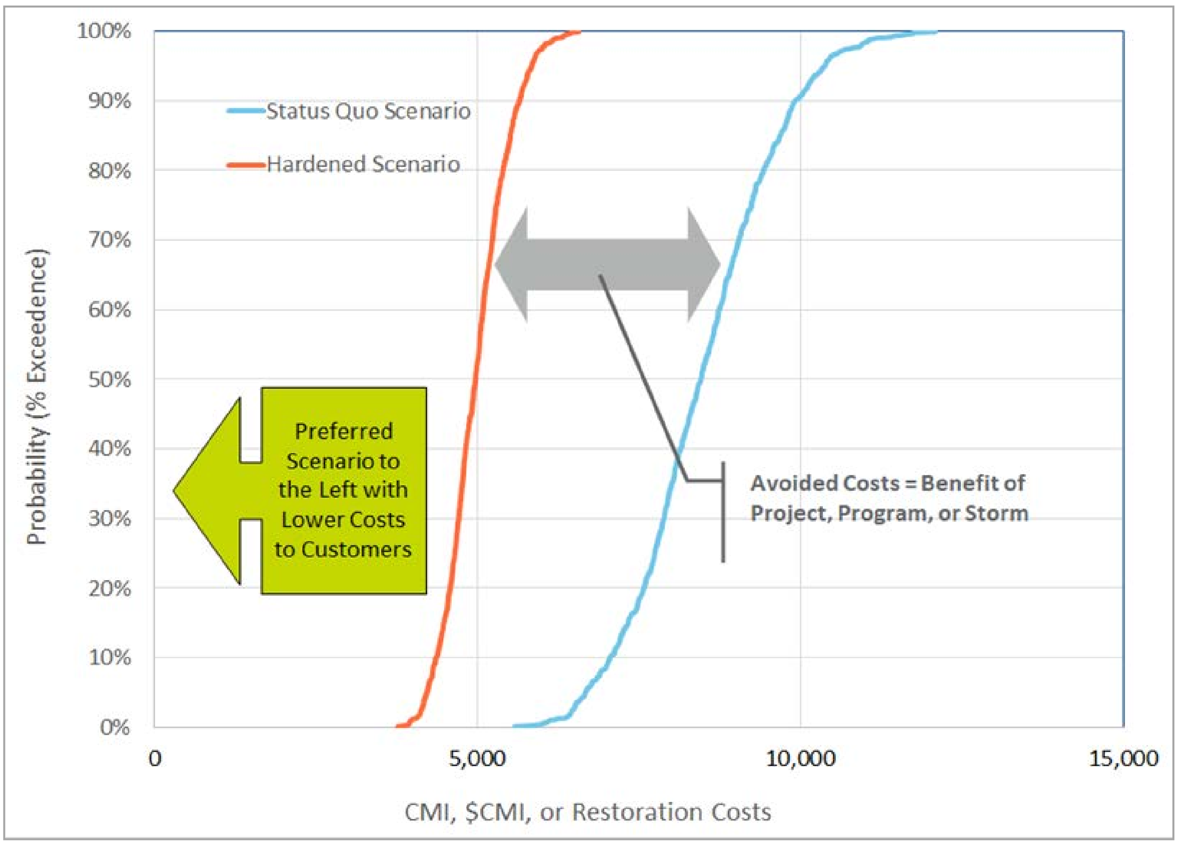
Distribution Overhead Feeder Hardening - The distribution overhead feeder hardening project costs are based on the number of wood poles that don't meet current design standards for storm hardening and the cost to include automation. Tampa Electric provided unit replacement costs based on the accessibility 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. The remaining circuits costs were based on the average of these values.

Transmission Access Enhancements – Tampa Electric provided all the project costs for the Transmission Access Enhancements as developed by a third-party.

Q36. How are the resilience results of the Monte Carlo Simulation displayed and how should they be interpreted?

A36. 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 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



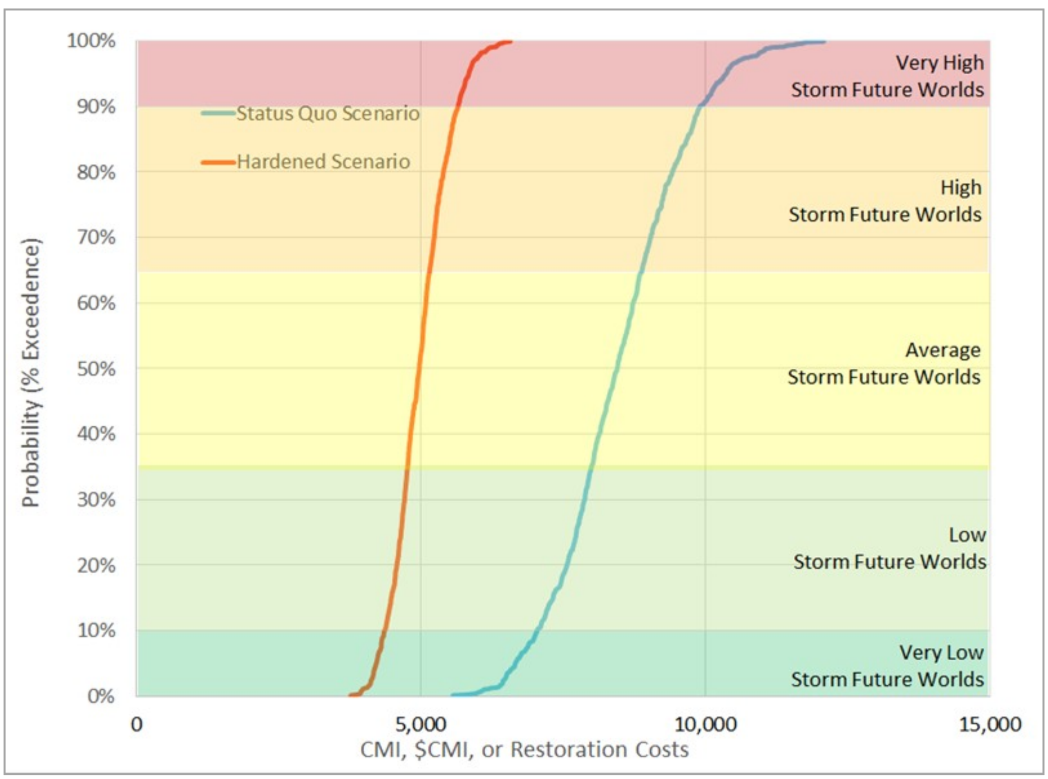
Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

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.

Q37. How do S-Curves map to potential Future Storm Worlds?

A37. Figure 9 below provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

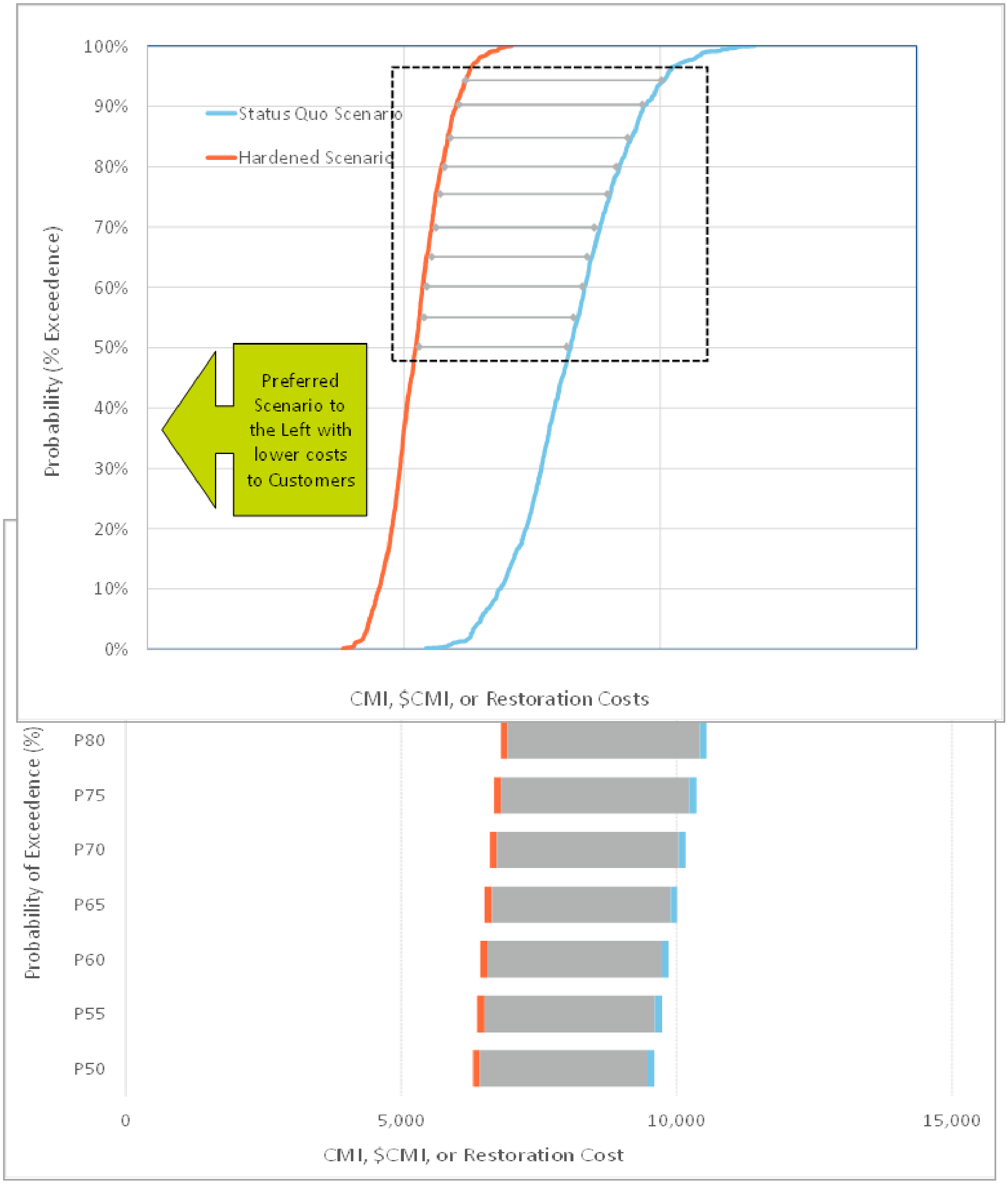
Figure 9: S-Curves and Future Storms



Q38. How are the S-Curves used to display the resilience benefit results?

A38. 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 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



Q39. Please describe the analysis to calculate resilience benefit for automation hardening projects.

A39. 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 2.

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. Tampa Electric has outage records going back 20 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 20 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 20 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.

Q40. Please provide an example of this calculation.

A40. 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.

Q41. What are the benefit results of this analysis for the automation hardening projects?

A41. Figure 11 and Figure 12 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

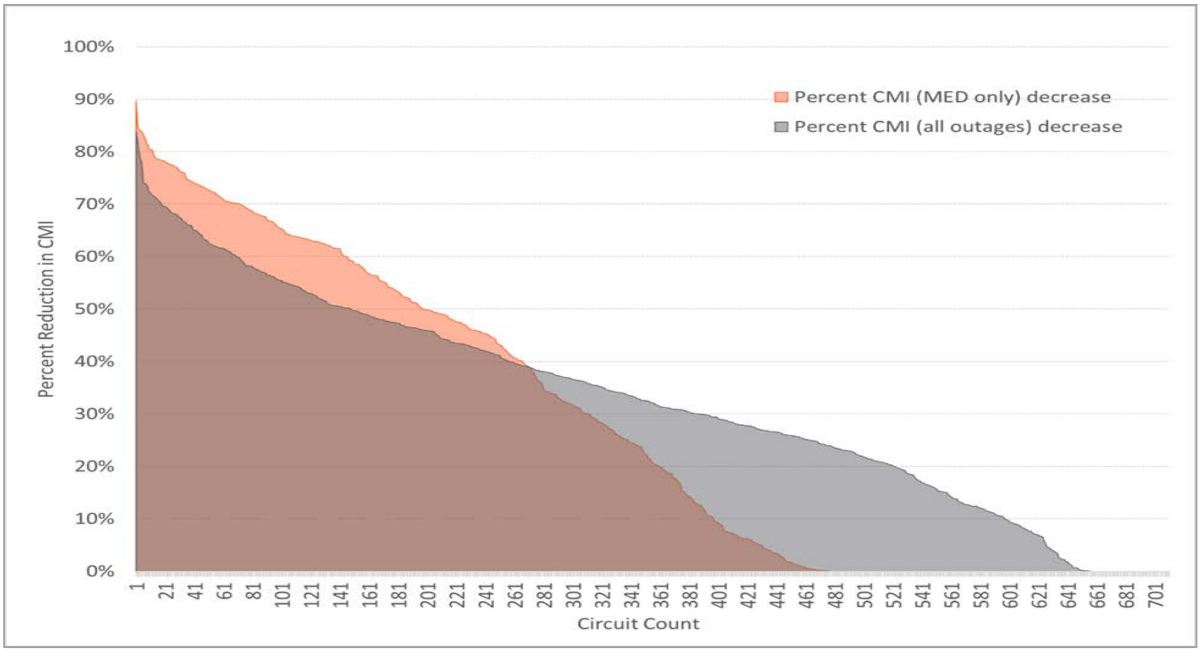
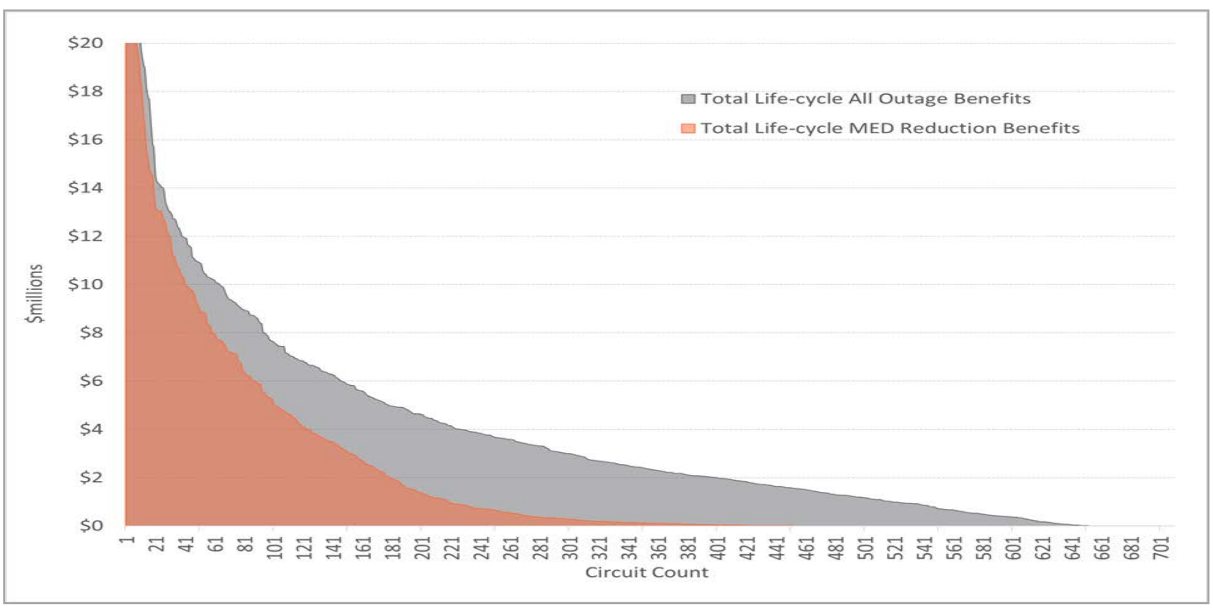


Figure 12: Automation Hardening Monetization of CMI Decrease



Q42. What are the specific outputs from the Resilience Benefit

module?

A42. 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

Q43. How were hardening projects prioritized?

A43. All the projects are evaluated and prioritized using the same criteria allowing all 13,855 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. Tampa Electric 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.

Q44. How and why was the budget optimization performed?

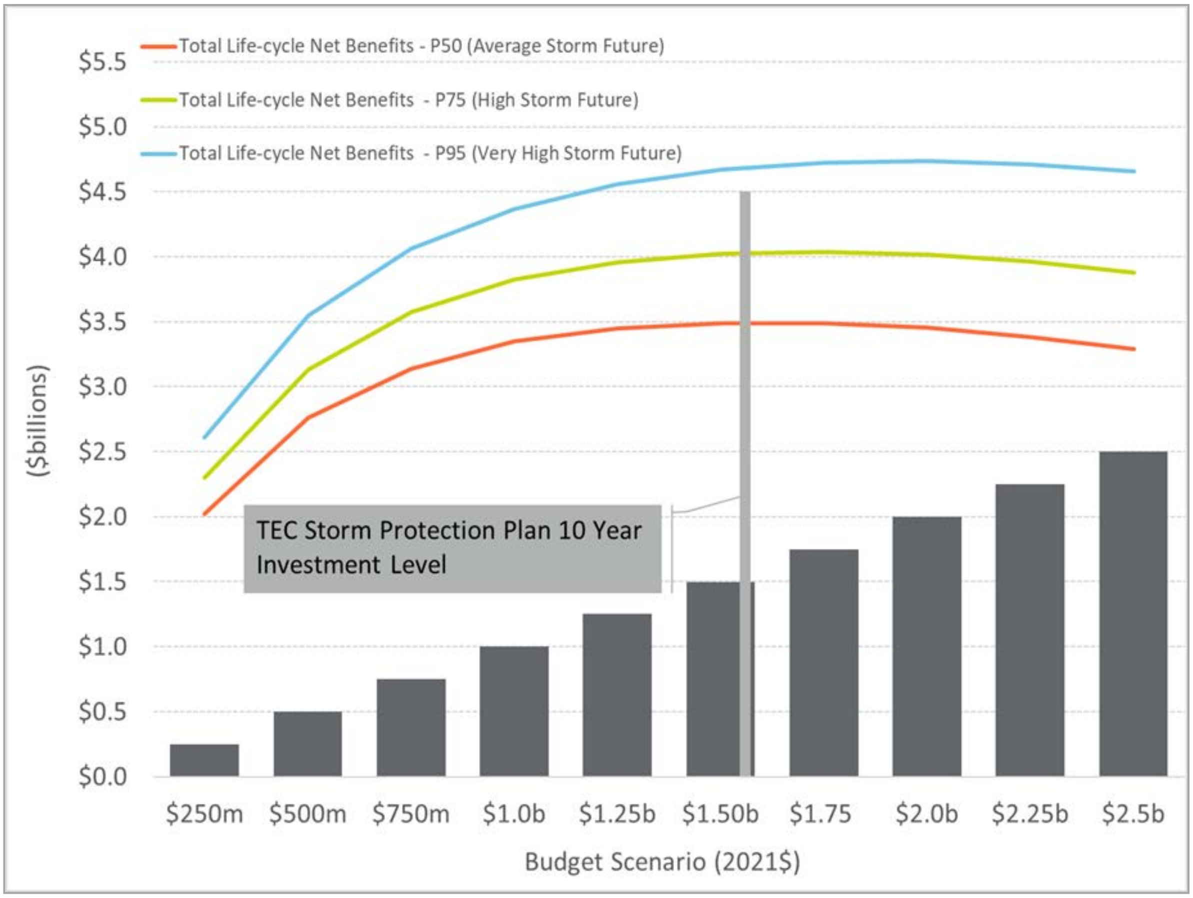
A44. The Storm Resilience Model performs project prioritization across a range of budget levels to identify the appropriate level of resilience investment.

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 Tampa Electric to gain capital deployment efficiencies by deploying resources to the same geographical area at one time.

Q45. What were the results of the budget optimization analysis?

A45. Figure 13 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 $1.25 billion with the benefit level flattening from $1.25 billion to $1.75 billion and decreasing from $1.75 billion to $2.5 billion.

Q46. What conclusions can be made from the results of the budget optimization analysis?

A46. The budget optimization results show that Tampa Electric's overall investment level is right before the point of diminishing returns showing that Tampa Electric's plan has an appropriate level of investment capturing the hardening projects that provide the most value to customers.

Q47. How was the overall investment level set and projects selected?

A47. Tampa Electric 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 Tampa Electric's Storm Protection Plan project identification and schedule, the Tampa Electric 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

Q48. What is the investment profile of the Storm Protection Plan?

A48. Table 5 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 $1.59 billion. Distribution Lateral Undergrounding makes up most of the total, accounting for 67.6 percent of the total investment. Overhead Feeder Hardening is second, accounting for 20.0 percent. Transmission Asset Upgrades makes up approximately 8.8 percent of the total, with Substation Extreme Weather Hardening and Transmission Access Enhancement site access making up 1.7 percent and 2.0 percent, respectively.

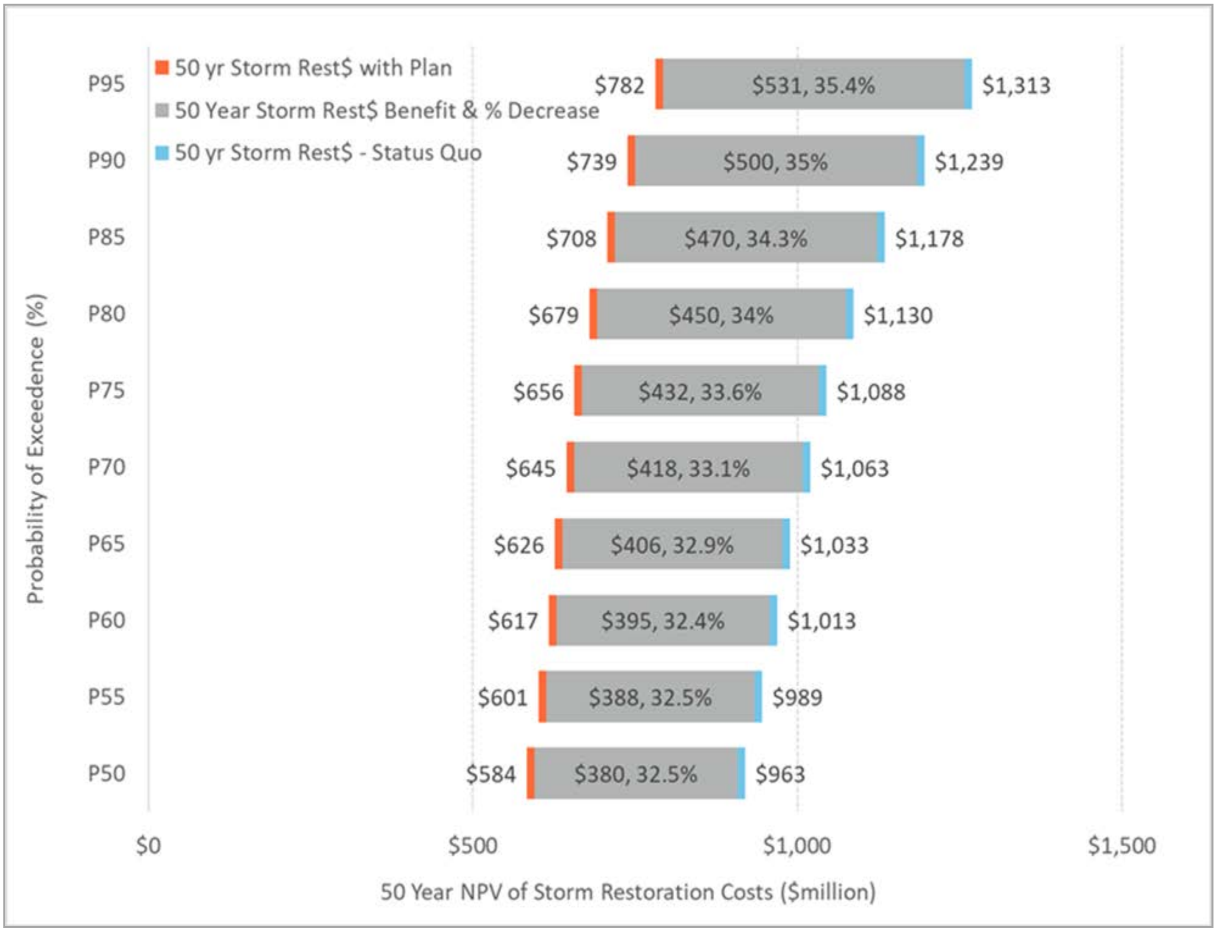
Table 5: Storm Protection Plan Investment Profile by Program (Nominal $000)

Year	Distribution Lateral Undergrounding	Transmission Asset Upgrades	Substation Extreme Weather Hardening	Overhead Feeder Hardening	Transmission Access Enhancement	Total
2022	$105,600	$16,500	$0	$33,300	$2,400	$157,800
2023	$104,500	$17,500	$700	$29,900	$3,000	$155,600
2024	$105,700	$17,500	$4,300	$30,000	$3,000	$160,500
2025	$105,100	$17,900	$2,700	$30,000	$3,700	$159,400
2026	$105,000	$18,200	$3,300	$30,000	$3,400	$159,900
2027	$105,600	$16,900	$2,900	$30,000	$3,400	$158,800
2028	$105,600	$17,300	$4,800	$30,000	$3,100	$160,800
2029	$105,600	$17,200	$700	$30,000	$2,800	$156,300
2030	$115,400	$0	$7,200	$37,000	$2,000	$161,600
2031	$115,400	$0	$900	$37,000	$4,400	$157,700
Total	$1,073,500	$139,000	$27,500	$317,200	$31,200	$1,588,400

Q49. What are the restoration cost benefits of the plan?

A49. Figure 14 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

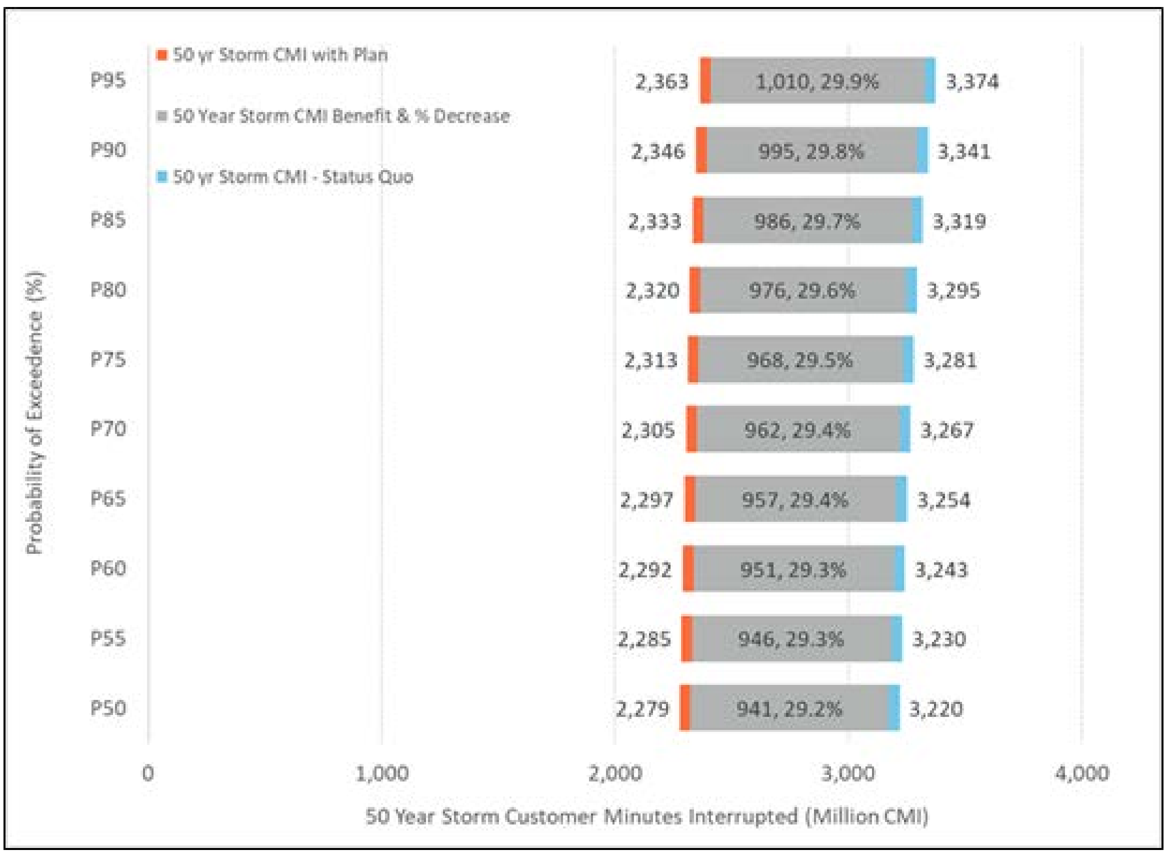


The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $960 million to $1,310 million. With the Storm Protection Plan, the costs decrease by approximately 33 to 35 percent. The decrease in restoration costs is approximately $380 to $530 million. From an NPV perspective, the restoration costs decrease benefit is approximately 24 to 33 percent of the project costs.

Q50. What are the customer outage benefits of the plan?

A50. Figure 15 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 29 percent decrease in the storm CMI over the next 50 years.

Figure 15: Storm Protection Plan Customer Benefit



Q51. What are the key take-aways from how resilience-based

planning assessment was performed?

A51. 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 by 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 Tampa Electric's 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 a 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 of 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 Tampa Electric 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 Tampa Electric to provide a higher level of system resilience for customers.

Q52. What conclusions can be made from the results of the resilience analysis?

A52. The following include the conclusions of Tampa Electric's

Storm Protection Plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.59 billion for Tampa Electric'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.
- Tampa Electric's Storm Protection Plan results in a reduction in storm restoration costs of approximately 33 to 35 percent. In relation to the plan's capital investment, the restoration costs savings range from 24 to 33 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 29 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 $0.65 to $0.78 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to

pay' customer surveys.

- Tampa Electric'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.

8. CONCLUSION

Q53. Does this conclude your prepared verified direct testimony?

A53. Yes.

BY MR. MEANS:
Q Mr. DeStigter, did you include any exhibits with your testimony?
A I sponsored the 1898 & Company report.
Q But that's a component of Mr. Pickles' exhibit, correct?
A That's correct.
Q And did you prepare a summary of your direct testimony?
A Yes, I did.
Q And would you please read that for us?
A Good afternoon, Commissioners. My direct testimony summarizes the approach and the methodology to, one, calculate the customer benefits of hardening investments; two, prioritize those hardening investments within the 10-year plan; and then three, establish an overall investment level for the plan.

The first item, customer benefits. My direct decision shows -- testimony shows how they were estimated in direct alignment to the storm protection plan cost recovery statute and rule. Specifically the 1898 & Company evaluation estimated the decrease in restoration costs and the avoided outages for all potential hardening investments.

Avoided outages were calculated in terms of the storm customer minutes interrupted, or CMI as it's often referred to. Our evaluation broke down Tampa Electric's T&D system into approximately 13,800 potential hardening investments. So for this twofold benefits assessment, we calculated the decrease in restoration costs and the decrease in customer outages for all 13,855 potential hardening investments.

For the second item, my direct testimony describes how projects were prioritized for investments, leveraging this business justification approach, this twofold approach I just described, projects were initially prioritized based on a resilience benefits cost ratio.

Resilience benefits are the avoided restoration costs and the monetized customer minutes interrupted. Resilience benefits cost ratio prioritizes investments that provide the most benefit to customers given execution and budget realities.

For the third item, establishing an overall investment level. Resilience benefit assessment was leveraged to perform a budget scenario analysis identifying that at approximately one-and-a-half billion dollars we start to see the point of diminishing returns for hardening investments. This is based on the current condition of Tampa Electric's system.

My testimony shows that the plan is expected to produce a decrease of approximately 33 to 35 percent in storm restoration costs, and approximately 29 percent decrease in customer outages over the next 50 years.

Finally, my testimony demonstrates that the Tampa Electric hardening investment plan is reasonable, maximizes customer benefits and developed with a complete alignment to the statute and rule.

Thank you.

MR. MEANS: Mr. Chairman, we tender the witness for cross.

CHAIRMAN FAY: Great. Thank you.

Office of Public Counsel, you are recognized.

MS. WESSLING: Thank you, Chairman.

EXAMINATION

BY MS. WESSLING:

Q And good afternoon, Mr. -- can you say it for me one more time?

A DeStigter.

Q DeStigter, okay.

So TECO hired your company, 1898, specifically to assist with the prioritization of storm hardening programs and projects with regard to extreme weather, correct?

A Correct.

Q And are you familiar with OPC Witness Mara's testimony, have you reviewed that?

A I have not.

Q Well, with regard to TECO's distribution feeder sectionalizing and automation project, it uses communication between devices and operations center to allow the distribution network to be reconfigured automatically. Is it correct to characterize that as a fault isolation system?

A Distribution automation is one component of what we FLISR, fault location isolation system restoration.

Q Okay. Does that work on radial feeder or only on feeders that are tied to adjacent feeders?

A Distribution automation is for radial feeders that have connections through devices to other feeders. So we would call that a normally open device.

Q All right. This type of fault isolating system is very effective in reducing outage times on blue sky days, or maybe even on stormy days, is that correct?

A It can be effective in many instances. Yes.

Q Okay. During an extreme weather event, is it common that an entire substation would lose power?

A That is a potential consequence of a major event. Yes.

Q Even two or three adjacent substations might lose power in an extreme weather event, correct?

A It could happen. Yes.

Q With multiple substations without power, can this fault isolation system work to isolate faults on a distribution feeder served from these multiple substations without power?

A In the case where the adjacent feeder is not energized, the -- you cannot switch over use deploying the distribution automation scheme. However, what we have done is performed an evaluation of that, and looked at Hurricane Irma. And in that instance, approximately 70 percent of the time a circuit had an adjacent feeder that was available for switching if distribution automation had been in place for those circuits.

Q In the model developed by 1898 for the resilience benefits report, did the model assume adjacent feeders would be available during extreme weather events and, therefore, illustrate benefits that would not be realized?

A I would not characterize the evaluation that way. What we performed is what I would call a conservative estimate of distribution automation benefit. We looked at Tampa Electric's storm -- outage records for the last 20 years, and we only looked at it for what we termed major event days. So these are days where a large portion of the system is without service. Upon that evaluation, we determined -- we assumed that the adjacent circuits would be available.

One thing to note, though, is Tampa Electric turns off their outage management system during major events. So if you look at their last 20 years of historic additional outages, it does not include hurricanes like Hurricane Irma in it. And so I would argue that our benefits that we have outlined for distribution automation are actually conservative, and would provide more in terms of storm.

Additionally, the evaluation did not quantify the benefit -- or did not use the benefits from blue sky as well. So in that fashion, the overall benefits of distribution automation are understated relative to what customers would get for that investment.

Q All right. I would like to discuss rate impact, the subject of rate impacts with you. And I apologize, I don't think I had page numbers on your testimony. Do you have a copy of it, of your testimony?

A I do have a copy of my testimony.

Q Okay. If you could turn to question 28. It's about halfway through.

A I am there.

Q Okay. There you discuss how storm restoration costs were determined by 1898 and TECO, correct?

A The question is: How are restoration costs allocated to the outage for each major storm event.

Q I guess your answer -- the beginning of that answer, could you read the first two lines, or that first sentence?

A The storm restoration costs were calculated for every asset in the storm production model, including wood poles -- you want me to keep going?

Q Yeah, sure. If you can --

A Wood poles, overhead primary, transmission structures, to include steel, concrete and lattice, transmission conductors, power transformers and breakers.

Q And could you go ahead and read the next two sentences as well?

A The costs were based on storm restoration costs multipliers above planned replacement costs.

Q And the last sentence on that page, beginning on line 22, with they are, would you read that?

A Line 22: They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms.

Q Okay. And in this answer, when you are referring to multipliers, can you explain for the record what you mean by multipliers?

A Yeah. So during major events, large ones, hurricanes Category 1 and above, it is often the case that foreign crews are brought in to the service territory to support, and based on the costs those crews have, you can -- the cost to replace a wood pole can, on average, be anywhere from two to four times the cost if you were to just replace that pole on a normal blue sky day in a planned project. And that is a large part of the benefits to the plan, is to mitigate the need for all of those reactive pole replacements, other infrastructure upgrades that happen in what we call storm reactive mode, which can be quite costly.

Q And you just read this, but you would agree that the multipliers, as described here, are based on expected inventory constraints and foreign labor resources needed for the various assets, correct?

A That's what my testimony says.

Q Okay. And you said that, I believe you said that TECO and 1898 worked together to determine what multipliers would be appropriate to add to the actual restoration costs?

A That is correct.

Q Okay. And for those multipliers and the costs themselves, I assume you were using material and labor costs from before, when this report was finalized, in order to calculate those numbers, is that accurate?

A We went through a lengthy process to identify -- as you will see there, the multipliers are above planned replacement costs. So those planned replacement costs were evaluated in the first quarter of this year what estimates we would have. The multipliers did not change.

Q Okay. And your report, it's attached to Mr. Pickle's exhibit, the resilience benefits report, that's dated February 16th of 2022?

A That is correct.

Q Okay. And the rate of inflation that the United States has experienced since February 16th, 2022, is not something that is factored into the calculations within your report, correct?

A I would not say that.

Q So the rate of inflation that the U.S. has experienced since -- between February 16th and now is incorporated into your report?

A In understanding the -- those planned replacement costs, the evaluation took note of current escalation and pricing and expectations in terms of what it would cost to purchase poles, conductors, et cetera, for the unit costs. We wanted to provide an accurate assessment of what the costs would be. So it does -- it does not officially include actual inflation from February to today, but it includes the inflationary realities that were at the time when we made those estimates.

Q   Do those -- what do you use to estimate inflation, do they match the actual inflation that we've experienced?

A   For a planning study of our type, it is not necessary for the prudency assessment of the benefits to have the kind of granularity into exact specific numbers on that side.

Q   Just so I understand it. So that's a no, and then accompanied by the explanation you just provided?

A   It does not include the actual specific inflation rates. It's important to note that different inflation rates exist based on types of materials, labor, et cetera.

What we did in terms of develop to filling out those planned costs is worked with Tampa Electric and pulled in historical actual projects, what those cost realities were, and adjusted our unit cost information for that.

Q I guess what I am getting at, though, is you would agree there has been a very high rate of inflation since February, since your report was finalized, right?

A Inflation has been very high for a while, yes.

Q And does your report -- looking backwards now, not at the time you finished the report, but does your report match the actual rate that we've experienced?

A As of the filing of the report, our evaluation included the inflationary realities to date -- to the date of the report.

Q As of today, August 3rd?

A We could not know the actual inflation of the future as of February --

Q Right.

A -- when the report was done.

Q I agree, but I am just wondering, with the information included in your report, and all the information you used to make that report, and looking back from today, is what you anticipated in that report, does that match the realities that that we are experiencing today?

A I would say that the report's assessment, its main conclusions of what it has drawn are unchanged given the realities of inflation for the last four or five months.

Q So the costs that you predicted and estimated in that report match -- are unaffected by the rate that we've experienced -- the rate of inflation that we've experienced?

A In terms of the actual costs, so the -- let's make sure we are clear here. The costs to execute the planned projects or the costs if a storm were to occur?

Q The cost to -- the former.

A The former. So related to the unit costs, I would refer you to Witness Plusquellic on how those detailed unit costs were established based -- and largely, they were based off of projects that had been completed and indications from contractors in terms of where unit -- where pricing was moving in terms of the cost for line transformers, poles, conductors, et cetera.

Q So for the same program, if it were filed -- if TECO were to have filed it today, would it be more expensive than the 1.6 billion?

A I cannot comment on that. You would have to know inflationary realities between now -- for every year for the next 10 years to perform that. We assume -- so you can't -- you can't know that for certain.

Q All right. If we could flip to it your report, which is DAP-1, Appendix F, and go to page 71 of

82.

A Had you said 71 of 82?

Q Yes.

A I am there.

Q All right. And you see Figure 6-1, Budget Optimization Results?

A Yes.

Q All right. And does this figure sort of summarize a lot of what the report is, you know, a lot of what the report contains? It's a lot of conclusions from your overall analysis?

A Figure 6-1 is one of many that is necessary to understand the results of the entire analysis performed by 1898 & Company.

Q All right. So can you explain what this chart does represent, then?

A Yes. So as I mentioned in my summary, 1898 & Company was tasked with helping to identify at what point do we start to find diminishing returns in terms of hardening the system. And so with that business case performed, that business justification performed for all 13,800 projects, we monetized that customer minutes interrupted.

So what you are seeing there in the orange line, the green line and the blue line are the sum of the restoration benefits and the monetized customers -- customer minutes interrupted based off of an investment of 250 million over 10 years, 500 million over 10 years, et cetera.

That evaluation was based on what we would call an unconstrained world. We did not take into the realities of how many crews we had, or how much -- how fast we could do that work, et cetera. It was assuming let's rank all the projects from best to worst, and essentially find that point where we are starting to invest in a project that isn't providing those full benefits.

So what our analysis shows is that at approximately one-and-a-half billion dollars, the net benefits to customers start to flatline in that situation. And so for the purposes of the evaluation, identifying that one-and-and-a-half-billion-dollar mark allowed us a point to say, all right, now we can start to build in a more constrained model, a constrained plan from that.

Q And within this chart -- first of all, this is a look at the plan as a whole, correct? There is no sub -- there is no breakdowns for programs or projects, correct?

A Correct. This plan assumes a complete

unconstrained that I could go rebuild 200 miles of underground one year, and then do 12 substations the next year, and then do all transmission the next year. It is -- these plans are not -- they are academic, hypothetical in terms of they are execution realities.

Q And at the bottom of the chart, it says: Budget scenario 2021 dollar sign, that means that it was 2021 dollars that were used to calculate the results of this chart, correct?

A Dollars were discounted into 2021 dollars.

Q Okay. So they would be more expensive today?

A What this chart represents is that if I put in $1.5 billion in that one example into a bank account in 2021, it would allow us to pay for all of the investments from 2022 to 2031 of the plan. So life cycle, or discount cash flow methodology, we would just discount that based off of an expected return put into investment. So this is not nominal dollars. This is what we would call 2021 dollars.

Q And looking at this chart, isn't it fair to say that if the budget were reduced to approximately 850 million, customers would still realize a benefit of approximately 3.25 billion?

A No, that is not the way to utilize this chart.

The purpose of the chart is to identify the point of diminishing returns in terms of an overall investment. As I just discussed, each one of those gray bars is an unconstrained world. So if you wanted to have a $750 million plan, there would have to be a whole level of effort to understand what that amount of money would actually employ in terms of executing those realities.

So you have to spread investment over time, over different programs to have consistency. For execution, you have to take in additional realities in terms of we can't just invest in one area, we have to spread the area around because our crews can't be on top of each other to execute the work safely, et cetera.

So this chart was developed as part of the journey to identifying the long-term investment plan. So the purpose of the chart was essentially to say, okay, look at one-and-a-half billion dollars we start to see the point of diminishing returns. Now let's go build an executable real plan based off of that. So none of these gray bars are actually executable real plans.

MS. WESSLING: One moment.

Nothing further.

CHAIRMAN FAY: Great. Thank you.

Next, Mr. Moyle. FIPUG.

MR. MOYLE: Thank you.

EXAMINATION

BY MR. MOYLE:

Q I have a few questions, and a couple of questions were punted to you by your colleague who was on the stand previously.

I -- one of the questions I think that got punted was I had asked, you know, was there a bright line with respect to diminishing returns. Could you take a stab at that?

A Yeah. So for diminishing returns, as the figure we were just on, Figure 6-1, those that at approximately one-and-a-half billion dollars we start to see the point of diminishing returns for the plan.

Q And a flatline is where you established as, okay, there is no -- no benefit, but then there is no cost either, correct, at that point on a flatline?

A The flatline shows that costs and benefits are essentially increasing at the same rate --

Q Right.

A -- so you aren't -- yeah.

Q Right. But if you can't run the model, at some point you would -- it would presumably show that the cost exceeded the benefits, correct?

A Correct. So if you look at Figure 6-1, you will notice in the two-and-a-half-billion-dollar scenario over 10 years, you start to see those orange, green and blue curves to start --

Q Right.

A -- going, the slope goes negative.

Q As part of your work, or could the -- could the company run this type of a model on a programmatic level? I say programmatic -- are you familiar with the statute that is involved in this -- in this case?

A I am familiar with the statute.

Q And it says -- it defines programs and it defines projects, right?

A Correct.

Q So when I ask you that question, I am using it in reference to the statutory definition of programs. My question is: Could you run a similar model with respect to programs so that you could look maybe with a little more granularity on programs as to which ones provided great benefits, which ones were neutral and which ones were negative?

A The model has the capability to perform that kind of analysis.

Q And was it done in your work?

A The modeling, in terms -- so as we look at the -- I think your question is getting around to the process in terms of selecting projects within individual programs. And within the testimony and the report, we lay out at a high level how we have performed the development of the individual programs, which projects were selected.

The process involved essentially what I would call kind of optimization at the program level, but it incorporated different realities. For example, on lateral undergrounding, we knew that we had to spread the work around just from an execution perspective. Tampa Electric's distribution engineering and planning teams are organized regionally, and so we had to tell the model to have a minimum level of work in each of the regions so that we wouldn't have crews on top of each other all the time. And so annually each year there is a singular -- there is a minimum level of work that is going to each region.

Additionally, we wanted to have consistency over years for that level of investment for execution-based purposes as well. And so what we did is we took this optimization model, this Figure 6-1, which is that unconstrained world, and we started to incorporate real world constraints in terms of execution realities. A, if we are going to be in this part -- if we are go to be doing this on a circuit, we should probably do this other thing on the circuit as well from this other program and organized it that way.

And so also looking at transmission projects, understanding different outage requirements, if you do transmission line A one year, you cannot do transmission line B in that same year because of outage issues and the stability of grid. So in our model we are able to code that in so that those realities were incorporated.

And so the model is essentially -- the plan, the 10-year plan, is a balance between identifying the highest benefit projects first but also incorporating those realities by program. And additionally, you know, how many poles can we do per year on a transmission line, et cetera.

Q Okay. And what you were just describing was the constrained adaptation, correct?

A That is correct.

Q In terms of the projections, is there, in your professional opinion, a preferred way of making those projections based on looking into the future about, well, I think the pole rates are going to go up by this? I mean, I am trying to understand future projections versus maybe looking at historical costs, and then making adjustments to historical costs by adding new things like inflation. How do you go about deriving the

numbers that are used, from a historical perspective or a prospective?

A Excellent question.

Historically, our inflation rate has been very stable. And so in terms of modeling, in terms of projections of what costs may be, we have been able to assume what the last 20, 30 years average rate has been.

As we look through the future, we want to make sure to incorporate the short-term realities, but also making sure to say, hey, do we think this inflationary world is going to be maintained for the 10 years, 50 years of the modeling?

We did not elect to do that. We took a more conservative view that we would come back to a steady state inflation that is based on historical since our model is a 50-year forward-looking model.

Some of the realities regarding internal for costs for the first part of the plan reflect actual inflation that Tampa Electric has seen in some of the indicative inflation that the contractors was communicating to them regarding those realities. I will refer to you Witness Plusquellic who has the additional details on what that is looking like at this moment.

Q Okay. You made a comment in your opening statement about the model -- the model, or Tampa

Electric opts to turn off for major storm events. What did that reference?

A So an outage management system allows you to record any of outage on the system and start and stop times to for each outage, the cause of the outage, the number of customers impacted, et cetera.

During major events, because of all the different outages that occur, it can be chaotic to record all of those in realtime. And since, for the reliability metric requirements, they get to exclude those sort of events from their calculation, they don't -- they don't need to record that.

And so Tampa Electric has historically turned off their outage management system during those major events. They still record the impact of the outage, they just do it in a different way, not within the outage management system.

Q So when they do it in a different way, will they be able to measure how the improvements under the storm protection plan have faired in a storm event?

A So it's important to know, the analysis we performed using historical outage management system was for the distribution automation investment plan only. For all of the infrastructure hardening pieces, the lateral undergrounding, primary, you know, mainline feeder hardening, et cetera, we employed a different methodology that, as outlined within the report and my testimony, to calculate those customer impacts.

Q What's the basis for your statement that replacing a wood pole is two to four times as expensive to do so following a storm event as compared to blue sky day?

A The basis for that is in actual data from Tampa Electric's own experience in terms of the cost to restore infrastructure during those events. So they have counts of, during major events, counts of wood poles that got impacted, lines that went down. And when you put that on a per pole basis, and then compare that to the cost to replace a pole during a normal planned event, or a planned work order, that's how we determined those multipliers.

Q Did you all look as to what went into that? Whether that was out of -- they called them foreign, I think -- foreign crews come in and charging, you know, rates that are above typical rates, or is there not inventory for poles, and you got to go and buy poles in a storm event? I mean, why -- it seems -- it struck me as being particularly high, if it's four times, up to four times what it would cost to replace a wooden pole during a storm. Did you look at any of the detail on

that?

A We did not do a forensic detailed analysis of those multipliers. However, they aligned with expected multipliers that we've seen in other areas.

Q And so in terms of running your model, did you use a four times wood pole replacement sum as an input in your model, or two to four times input?

A Depending on the storm event, we had a multiplier of anywhere from two to four times based on the activity. What's important to note is that that multiplier is used to help to understand where the restoration costs are likely to happen across the system.

Q Does 1898 work for other utility companies doing this kind of modeling that you have done for Tampa Electric Company?

A Yes, it does.

Q Okay. And 1898, is that how long the company has been around? Where did that name come from?

A So, yeah, 1898 & Company is the business and technology arm of Burns & McDonnell. Burns and McDonnell was established in 1898. So it is a homage to our engineering pedigree.

Q Thanks for your time.

A Thank you.

CHAIRMAN FAY: Ms. Eaton?

MS. EATON: I don't have any questions. Thank you.

CHAIRMAN FAY: Great. Staff?

EXAMINATION

BY MR. IMIG:

Q Good afternoon. Do you have a copy of the SPP rule? Please refer to subparagraph (3)(d)(1).

A Yes.

Q Okay. Where are the estimate of reduction in outage times and restoration costs located in TECO's plan?

A They are located in many areas, but the easiest one to reference is within -- it is within -- apologies -- their report. So I will refer you to page 71 of 78 of the filing. The bottom page has 103.

Q Thank you.

MR. IMIG: No more questions.

CHAIRMAN FAY: Okay. Commissioners?

Commissioner Clark.

COMMISSIONER CLARK: Yeah, just one question related to following up on Mr. Moyle's question regarding pole replacement costs during a storm.

Are the actual costs calculated differently during a storm than they would be during a planned maintenance event? I am specifically thinking of how is labor handled in a work order process as opposed to a storm event?

THE WITNESS: Most utilities have a work order system that includes what we call compatible units. It's based off of if I had a pole, if I had a pole top like this, et cetera, what are -- and they have assumed labor rates based on -- based on their actual costs from projects, which includes the cost of Tampa Electric crews as well as local contractors, what that cost would be.

When you look at the cost of a major event, utility -- utilities leverage the mutual assistance contract that they have with other utilities, and that contract outlines the various costs in terms of repaying, say, a utility from up north coming down to serve with storm restoration activities.

COMMISSIONER CLARK: More specifically, I am -- and I think you are an engineer not an accountant, but is labor handled differently from an accounting perspective in a work order process as opposed to a -- as opposed to a storm process in terms of capitalization of labor costs and things of that nature?

MR. MEANS: Commissioner, our witness Richard

Latta, who is testifying later, would probably be the best one to answer that.

COMMISSIONER CLARK: Thank you very much. Thanks.

THE WITNESS: Sure.

CHAIRMAN FAY: We'll move on to redirect.

MR. MEANS: Thank you, Mr. Chairman. Just a few quick questions.

FURTHER EXAMINATION

BY MR. MEANS:

Q So, Mr. DeStigter, the benefits you calculate in your plan include a restoration cost and avoided outage -- avoided restoration costs and avoided outage times, is that correct?

A That's correct.

Q And I understand from your testimony that you read earlier that you calculated restoration costs in terms of the cost to replace an asset that has failed following a storm?

A That is correct.

Q And part of that cost, obviously, would be labor costs and material costs, correct?

A Yes.

Q And if we are in an inflationary environment and those go up, then those components for the avoided

restoration costs would go up too, correct?

A That is correct.

Q So the avoided restoration costs would go up if we stay in an inflationary environment, hypothetically?

A Yes, sir. So in a high inflationary world, the benefits -- the benefits side of the ledger would go up as well as the cost side of the ledger. It impacts both.

Q And just one more clarifying question. Mr. Moyle was asking you about the analysis you performed maybe at a program level.

Just to clarify, you calculated estimated costs and estimated benefits for each of the, I think you said 13,000 possible projects, is that correct?

A That's correct.

Q And those can be rolled up to the program level, is that correct?

A Yes. Our analysis was foundationally what I would call bottoms-up. We estimated the benefits at each project. And then for the program, we said, these are the hundred projects. So the sum of all those hundred projects would equal the total benefits for the program level.

MR. MEANS: Thank you. No further questions.

CHAIRMAN FAY: Okay. Thank you.

I do not believe we have any exhibits.

MR. MEANS: No exhibits.

CHAIRMAN FAY: Okay. Great.

Mr. DeStigter, you are excused. I believe you are the first one without rebuttal. So you are done.

(Witness excused.)

CHAIRMAN FAY: Mr. Means, we will move to your next witness -- oh, Mr. Wahlen, we will move to your next witness.

MR. WAHLEN: I am at the table now.

Tampa Electric calls Mr. Richard Latta to the stand, please.

Whereupon,

RICHARD LATTA

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

EXAMINATION

BY MR. WAHLEN:

Q Good afternoon.

A Good afternoon.

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

A My name is Richard J. Latta.
Q And were you previously sworn?
A Yes, sir, I was.
Q Who is your current employer and what is your business address?
A My current employer is Tampa Electric Company, and I work at 702 North Franklin, Tampa, Florida, 33602.
Q And you are not a lawyer, you are an accountant?
A That is correct.
Q Very well.
Did you prepare and cause to be filed in this docket on May 11th prepared direct testimony consisting of 12 pages?
A Yes.
Q And that's testimony that was originally filed by Sloan Lewis but you have adopted it?
A That is correct.
Q If I were to ask -- do you have any corrections to your testimony?
A I do. Page eight, line 24 of my direct testimony mentions return on equity percentage, it states 9.5, it should have been 9.95. That did not impact any calculations.
Q Okay. With that correction, if were to ask

you the questions contained in your prepared direct testimony today, would your answers be the same as those contained in the document?

A   Yes, sir. They would.

MR. WAHLEN: Mr. Chairman, we would ask that Mr. Latta's prepared direct testimony as corrected be inserted into the record as though read.

CHAIRMAN FAY: Show it entered.

(Whereupon, prefiled direct testimony of Richard Latta was inserted.)

AUSLEY & MCMULLEN

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May 11, 2022

VIA: ELECTRONIC TRANSMISSION

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

In re: Review of Storm Protection Plan pursuant to Rule 26-6.030, F.A.C.
Tampa Electric Company; Docket No. 20220048-EI

Dear Mr. Teitzman:

Attached is Tampa Electric Company's Notice of Witness Substitution along with the Testimony of Richard J. Latta, Utility Controller for Tampa Electric Company.

Sincerely,

Malcolm N. Means

Malcolm N. Means

MNM/bmp
Attachment
TECO Regulatory Department

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Review of Storm Protection Plan Pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company	))))	DOCKET NO. 20220048-EI FILED: May 11, 2022

TAMPA ELECTRIC COMPANY'S
NOTICE OF WITNESS SUBSTITUTION

TO: ALL PARTIES OF RECORD

Please take notice that Richard Latta, Utility Controller for Tampa Electric Company, will serve as Tampa Electric's witness in place of Tampa Electric witness A. Sloan Lewis, who previously submitted testimony in this docket on April 11, 2022. *See* Doc. No. 02353-2022. Mr. Latta's Direct Testimony, which is attached, will substitute for Ms. Lewis' testimony. This Direct Testimony is identical to Ms. Lewis' other than the responses to those questions that ask about the witness' identity and qualifications.

DATED this 11th day of May 2022.

Respectfully submitted,

Malcolm N. Means

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Notice of Witness Substitution, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 11th day of May 2022 to the following:

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Malcolm N. Means

ATTORNEY

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220048-EI

TAMPA ELECTRIC'S 2022-2031 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

RICHARD J. LATTA

FILED: MAY 11, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

RICHARD J. LATTA

INTRODUCTION:

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

A. My name is Richard J. Latta. 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 Utility Controller.

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

A. My duties and responsibilities include maintaining the financial books and records of the company and for the determination and implementation of accounting policies and practices for Tampa Electric. I am also responsible for budgeting activities within the company, which includes business planning, as well as general accounting, regulatory accounting, plant accounting, regulatory tax accounting, and financial reporting.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of South Florida in 2005 with a Bachelor of Science degree in Accounting and a Master of Accountancy in 2007. I am a Certified Public Accountant in the State of Florida. I joined Tampa Electric in 2001 as a Customer Service Representative. Upon completion of my Accounting degree, I joined Tampa Electric's Accounting Department in 2005 as a Financial Reporting Accountant working on the Conservation and Environmental clauses. I held and expanded my roles within Tampa Electric's Accounting Department until I moved to TECO Services Inc. in 2014 as a Corporate Accounting Manager. I returned to Tampa Electric's Accounting Department in 2017 as the Director of Financial Reporting. I am currently the Controller of Tampa Electric and have held this role since July 2021.

Q. Other than describing your background and qualifications, is the remainder of your testimony the same as that set forth in the testimony of A. Sloan Lewis that was filed in this proceeding on April 11, 2022.

A. Yes, it is.

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 2022-2031 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. RJL-1, entitled "Tampa Electric's 2022-2031 SPP Total Revenue Requirements by Program" was prepared under my direction and supervision. This Exhibit shows the Annual Revenue Requirement for the company's 2022-2031 SPP Programs.

CALCULATION OF THE ESTIMATED ANNUAL JURISDICTIONAL REVENUE REQUIREMENTS FOR TAMPA ELECTRIC'S 2022-2031 STORM PROTECTION PLAN

Q. What are 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 program are set out in my Exhibit No. RJL-1.

Total SPP Revenue Requirement (2022-2031)

YEAR	Revenue Requirements
2022	$47,877,941
2023	$69,433,375
2024	$87,196,252
2025	$107,222,775
2026	$127,418,631
2027	$147,273,337
2028	$167,170,904
2029	$186,443,478
2030	$205,728,771
2031	$224,897,513

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 SPP Cost Recovery Clause Rule.

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

A. Yes. The revenue requirement amounts shown above reflect all of the investments and expenses associated with the activities in the plan without regard to whether the costs are recovered through the company's existing base rates and charges or through the company's Storm Protection Cost Recovery Clause ("SPPCRC"). The SPP statute requires utilities to submit a plan explaining the utility's "systematic approach" to storm protection, which includes existing storm hardening activities that were previously established and were not "new" or "incremental" to the new proposed storm protection activities. In the company's Commission approved "2020 Agreement" the costs of some existing storm hardening activities that were being recovered through base rates were transitioned to recovery through the SPPCRC, while others were chosen to remain being recovered through base rates. The existing storm hardening programs that were chosen to remain in base rates were the following:

- Distribution Pole Replacements (Capital and O&M)
- Distribution Unplanned Vegetation Management
- Transmission Unplanned Vegetation Management
- Legacy Storm Hardening Plan Activities

The storm hardening programs that were chosen to be transitioned from base rate recovery to be recovered through the SPPCRC were the following:

- Transmission Asset Upgrades
- Distribution Planned Vegetation Management
- Transmission Planned Vegetation Management
- Distribution Infrastructure Inspections
- Transmission Infrastructure Inspections

Q. Is Tampa Electric intending to shift any of the current base rate recovered storm protection activities to recovery through the SPPCRC?

A. No.

Q. Did Tampa Electric make the agreed upon adjustments to ensure that no double recovery was occurring when it transitioned the base rate recovered activities to the SPPCRC?

A. Yes. Tampa Electric made two adjustments to ensure that all SPP costs that would be recovered through the SPPCRC were incremental and that no double recovery was occurring. First, the company reduced the filed amount of SPPCRC cost recovery in 2020 by $10.4 million dollars. This adjustment ensured that when Tampa Electric started the company's SPPCRC, those base rate activities would be removed from the total SPPCRC costs. The second adjustment was made by lowering base rates by $15 million dollars as of January 1, 2021 to recognize these activities would be removed on an ongoing basis from base rates and only be recovered through the SPPCRC.

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-2021-0423-S-EI on November 10, 2021.

Corrections on this page input by Court Reporter: Debra Krick

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-2021-0423-S-EI, which approved the company's 2021 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 of ~~9.5~~ 9.95 percent which is based upon the 2021 Stipulation and Settlement Agreement.

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 2022-2031 SPP meet the criteria for AFUDC eligibility.

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

A. Yes, Tampa Electric will continue to file for cost recovery of the estimated SPP costs through the SPPCRC.

CALCULATION OF THE ESTIMATED RATE IMPACTS FOR YEARS 2022-2024 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 2022, 2023, and 2024. 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
2022	2.70%	2.70%	1.17%	1.08%
2023	4.13%	4.13%	1.28%	1.19%
2024	5.31%	5.31%	1.37%	1.29%

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's 2021 Cost of Service Study that was approved in the company's 2021 Settlement in Docket No. 20210034-EI. 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 estimated charges are derived by dividing the rate class allocated SPP revenue requirements by the 2022 energy billing determinants (for residential) and by the 2022 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 the costs for each year 2022, 2023 and 2024 for those bills.

Q. Will the rates established through the 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.

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 continue to 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.

BY MR. WAHLEN:

Q Mr. Latta, did you also include an exhibit labeled RLJ-1 with your direct testimony?

A Yes, I did.

Q And was this exhibit prepared under your direction and supervision?

A Yes, it was.

MR. WAHLEN: Mr. Chairman, that exhibit has been pre-identified for the record on the comprehensive exhibit list as Exhibit 11, just for the record.

BY MR. WAHLEN:

Q Would you please summarize your testimony?

A Yes.

CHAIRMAN FAY: Mr. Wahlen, I have it listed as 10.

MR. TRIERWEILER: We have it as 10.

MR. WAHLEN: I am sorry. Then it's 10. I thought it was 11.

CHAIRMAN FAY: Okay.

MR. WAHLEN: Pardon me.

THE WITNESS: Good afternoon, Commissioners. My direct testimony demonstrates that the company's proposed 2022 to 2031 storm protection plan revenue requirements and estimated rate impacts comply with the storm protection plan rules.

The companies' proposed plan includes an estimate of the annual jurisdictional revenue requirements for each year over the 10-year horizon required by the rule. The 2023 revenue requirement is 47.9 million, and the increase is roughly 20 million a year over a 10-year period.

My testimony and exhibit demonstrate that the calculations of Tampa Electric's estimated annual revenue requirements were developed appropriately using cost estimates that were performed for each of the company's storm protection plan programs.

In addition, the revenue requirements were developed using the correct depreciation and return on asset methods as approved in Tampa Electric's 2020 stipulation and settlement agreement.

My testimony also provides an estimation of the overall customer impacts for each of the first three years of the plan as required by the rule. These rate impacts were developed using the appropriate allocation factors and methodology that was approved in the company's 2020 stipulation and settlement agreement.

Thank you.

MR. WAHLEN: Mr. Latta is available for

cross-examination.

CHAIRMAN FAY: Great. Thank you.

Office of Public Counsel. You are recognized.

MS. WESSLING: Thank you.

EXAMINATION

BY MS. WESSLING:

Q Good afternoon, Mr. Latta.

A Good afternoon.

Q So I understand you are the utility controller for Tampa Electric?

A That is correct.

Q Can you sum up what that means, that job means?

A Sure. It means that I am in charge of the company's financial reporting, some of the budgeting and forecasting, as well as the plant and tax calculations, as well as the regulatory accounting department.

Q All right. So it's safe to say your duties and responsibilities are pretty much exclusively accounting and financial related?

A Yes, that is correct.

Q Okay. So with regard to Tampa's storm protection plan, your involvement was limited to estimating the revenue requirements and rate impacts, correct?

A That is correct.

Q And you were not involved in determining which programs or projects to include in Tampa's storm protection plan, correct?

A That is correct.

Q All right. Nor were you involved in determining how much capital Tampa Electric would propose to spend on these programs and projects?

A That is correct.

Q You were given the information once it was decided on, as far as the capital expenditures, and you used that information to calculate the revenue requirement?

A That is correct.

Q Same thing, you were given the information, and you used that information to calculate the actual customer rate impacts, correct?

A Yes.

Q And your testimony describes the methodology that TECO used to calculate those rate impacts, correct?

A That is correct.

Q And did you review Mr. Mara's testimony at all?

A No, ma'am.

Q Okay. Let me know if you can answer this

question or not, but if the Commission approved Tampa Electric's current storm protection plan without any modifications, do you believe that it's an accurate number to say that Tampa Electric Company -- or customers will spend, on average, $2,061 in storm hardening costs over the next 10 years?

A As far as the -- say -- would you repeat your question?

Q Sure.

So is it fair to say that the average Tampa Electric customer would spend $2,061 total if this plan remains unchanged as filed?

A I guess, subject to check, it might. I know that the average residential customer is that uses a thousand kilowatt hours a month, what that impact would be.

Q Okay. Well, go ahead, what is that?

A That impact would be $3.26 .

Q That's per month?

A Yes. That is correct.

Q For 12 months, for 10 years?

A Yes -- well, I apologize. That would be for 2022.

Q Okay. And then it would be different in the following years?

A Yes.

Q And would it go up or down in the following years?

A Directionally it would go up.

Q And that's just -- I'm only asking you about 2022, '23 and '24, because you haven't calculated beyond 2024, correct?

A That is correct.

Q And that charge would be separate and apart from the customer's regular monthly utility bill, correct?

A Well, it's important to note that the rate that I have quotes includes portions that are included in base rates as well as the SPP clause.

Q Okay. You calculated the revenue requirements and customer rate impacts, excuse me, prior to April of this year, correct?

A That is correct.

Q And your calculations for those were based on fuel, material and supply prices prior to April of 2022, correct?

A They would have been projections at the time, yes.

Q All right. And so your calculations, you would agree, are probably low compared to now given

what's happened to the economy since you calculated those?

A Looking at it from a short-term perspective, yes. But we do -- I am sorry -- we do view the storm protection plan as more of a longer view.

Q Okay. And no one knows how long inflation is going to be high, or at what rate it's going to be, right?

A That is correct.

Q It could go higher?

A It could go higher. It could go lower.

Q And are you familiar with the actual estimated petition that Tampa Electric recently filed in the fuel docket?

A Yes. Yes, I am.

Q And I believe there is a copy there if you need it, but I believe it's already in evidence, either number 106 or 107?

MS. HELTON: It's 107.

MS. WESSLING: Okay. Thanks.

CHAIRMAN FAY: Thank you, Mary Anne.

BY MS. WESSLING:

Q So you are aware that Tampa Electric estimates that for 2022, it will under-recover $411 million as of now?

A Yes, ma'am, I am aware.

Q And do you know when -- if that number is approved, the 411 million, if that number is approved, do you know when customers would start seeing that on their bill?

A They would likely see impacts starting in January.

Q Of 2023?

A That is correct.

Q And that's the same time that they will see the impacts from this docket and the subsequent cost recovery docket, correct?

A That is correct. Although it is important to note that the overall recovery period of that projection has not been finalized.

MS. WESSLING: Okay. One moment.

Nothing further. Thank you.

CHAIRMAN FAY: Great. Thank you.

Mr. Moyle.

MR. MOYLE: No questions.

CHAIRMAN FAY: Okay. Ms. Eaton.

MS. EATON: No questions.

CHAIRMAN FAY: Staff?

MR. IMIG: No questions.

CHAIRMAN FAY: Commissioners?

Commissioner Clark, you are recognized.

COMMISSIONER CLARK: I will follow up with my question regarding labor costs. Can you share with me if there is a difference in the way labor costs are calculated, not simply calculated, but recorded during a storm event as opposed to a regular work order go change a pole labor? I assume you capitalize labor when you are doing an upgrade to the system during regular work order process.

THE WITNESS: Yes, sir.

COMMISSIONER CLARK: Is it handled the same way during storm work?

THE WITNESS: So typically, during storm restoration we would charge that to a deferred debit in which we do later evaluations as to whether or not it would be appropriate to charge it to the storm reserve.

COMMISSIONER CLARK: At any point in time, would you consider capitalizing that labor? I am assuming that you are not capitalizing labor -- let me rephrase that. I am assuming something.

Do you capitalize labor that's associated with doing pole changes?

THE WITNESS: So during a storm, if it was a capitalizable activity, I do believe we would capitalize.

COMMISSIONER CLARK: So you would come back? So there would be no difference in the actual cost related to a storm change-out versus a regular work order change-out in terms of labor, how things are calculated?

THE WITNESS: No, sir.

COMMISSIONER CLARK: Just an additional cost from having some other crew in place that has a higher rate or, you know, a storm rate applied to it at the time?

THE WITNESS: That is correct. It would just be a determination of if it's internal during straight time, overtime or if it was outside party.

COMMISSIONER CLARK: But we could probably assume that the time rate would be much -- significantly higher during a storm process?

THE WITNESS: Yes, sir.

COMMISSIONER CLARK: That would cause some of the -- I am trying to get to the what's causing that three to four times differential Mr. Moyle was asking about earlier, what is diving that, you know, four times cost. And it is strictly the rate of the contractors that we're using at the time?

THE WITNESS: That's what I would assume.

Yes, sir.

COMMISSIONER CLARK: Great. Thank you.

CHAIRMAN FAY: Great. Thank you.

No other questions?

With that, redirect, Mr. Wahlen.

FURTHER EXAMINATION

BY MR. WAHLEN:

Q Mr. Latta, the bill impacts that are described in your testimony are estimates?

A Yes, sir.

Q And the actual rates for cost recovery will be decided in the storm protection plan cost recovery clause, is that correct?

A That is my understanding.

MR. WAHLEN: No further questions.

We move Exhibit 10.

CHAIRMAN FAY: Okay. Without objection, show Exhibit 10 moved into the record.

(Whereupon, Exhibit No. 10 was received into evidence.)

CHAIRMAN FAY: And with that, you are dismissed for now, Mr. Latta.

MR. MEANS: We call David Plusquellic.

CHAIRMAN FAY: I don't know how Mr. Wahlen gets there so much quicker than you get there, Mr. Means.

Whereupon,

DAVID L. PLUSQUELLIC

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

EXAMINATION

BY MR. MEANS:

Q Can you please state your full name for the record?

A Good afternoon. My David name is David L. Plusquellic.

Q And were you previously sworn?

A Yes.

Q Who is your current employer and what is your business address?

A Tampa Electric. My address is 820 South 78th Street, Tampa, 33619.

Q And did you prepare and cause to be filed in this docket on April 11th, 2022, prepared direct testimony consisting of 63 pages?

A Yes.

Q And do you have any corrections to your testimony?

A There were corrections filed on July 13th.

Q Okay. And if I were to ask you the questions contained in your prepared direct testimony today, other than those changes, would your answer be the same?

A Yes, sir.

MR. MEANS: Mr. Chairman, we ask that his prepared direct testimony, dated April 11th, 2022, be inserted into the record as though read.

CHAIRMAN FAY: Show it inserted.

(Whereupon, prefiled direct testimony of David L. Plusquellic was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220048-EI

TAMPA ELECTRIC's 2022-2031 STORM PROTECTION PLAN

TESTIMONY AND EXHIBIT

OF

DAVID L. PLUSQUELLIC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID L. PLUSQUELLIC

TABLE OF CONTENTS

INTRODUCTION

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

A. My name is David L. Plusquellic. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director Storm Protection and Support Services. My business address is 820 South 78th Street, Tampa, FL 33619.

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

A. My duties and responsibilities include the governance and oversight of Tampa Electric's Storm Protection Plan ("SPP" or "the plan") development and implementation. This includes leading the development of the plan, prioritization of projects within each of the programs, development of project and program costs, and overall implementation of the plan. Organizationally, the Tampa Electric employees responsible for management and implementation of the Vegetation Management, Feeder Hardening, and Distribution Lateral Underground programs report through my organization. In addition, the Tampa Electric employees responsible for operating the SPP warehouse report through my organization.

Q. Please describe your educational background and professional experience.

A. I graduated from Kent State University in June 1996 with a bachelor's degree in Finance. In December of 2000, I graduated from the University of Akron with a Master of Business Administration degree specializing in Finance. I have been employed at Tampa Electric since November of 2019. Prior to joining Tampa Electric, I was employed at FirstEnergy from 1999 to 2018 in a variety of roles. During my 19 years, I progressed from an Analyst to a Director in roles covering financial reporting and analysis, business analytics, fossil fuel generation, renewable portfolio management, process and performance improvement, and Transmission and Distribution ("T&D") operations. For the final four years, I was Director of Operations Support at Ohio Edison, one of the FirstEnergy T&D operating companies. Throughout the 19 years, I played a leadership role in efforts that ranged from valuing businesses, entering into 20-year purchase agreements, evaluating and implementing storm process improvements, evaluating asset investments, and improving operational and safety performance.

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

A. The purpose of my direct testimony is to explain the eight Storm Protection Programs in the company's proposed 2022-2031 Storm Protection Plan ("2022 SPP" or "Storm Protection Plan"), which is included as Exhibit No. DAP-1 to the Direct Testimony of David A. Pickles. I will also describe the Storm Protection Projects associated with these programs as applicable. My testimony will describe how the company's 2022 SPP complies with Rule 25-6.030(3) by providing all the information required for each of these eight programs and their implementing projects.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I have prepared an exhibit entitled, "Exhibit of David L. Plusquellic." It consists of eight documents and has been identified as Exhibit No. DLP-1, which contains the following documents:

- Document No. 1 provides Tampa Electric's proposed 2022 SPP Projected Costs versus Benefits by Program.
- Document No. 2 provides the project detail for the Distribution Lateral Undergrounding Program.
- Document No. 3 is the Vegetation Management Program

study.

- Document No. 4 provides the project detail for the Transmission Asset Upgrades Program.
- Document No. 5 provides the Substation Hardening study that was performed in 2021 for the Substation Extreme Weather Hardening Program.
- Document No. 6 provides the project detail for the Substation Extreme Weather Hardening Program.
- Document No. 7 provides the project detail for the Distribution Overhead Feeder Hardening Program.
- Document No. 8 provides the project detail for the Transmission Access Enhancement Program.

TAMPA ELECTRIC’S 2022-2031 STORM PROTECTION PLAN

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

A. Tampa Electric’s 2022 SPP is comprised of eight distinct programs. The programs are as follows.

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. How is your testimony organized?

A. For each program, my testimony explains 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 T&D 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. I also explain the differences, if any, in the 2022 SPP programs as compared to the company's initial Commission-approved SPP programs.

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 2022 SPP programs?

A. No. The prepared direct testimony of David A. Pickles, submitted contemporaneously in this docket, describes the process Tampa Electric used to select and prioritize programs.

Q. Will your testimony address certain SPP projects?

A. Yes. In addition to explaining the required program details, for each program with projects, I also explain how the company developed the required project-level details for the first year of the 2022 SPP, 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. I also describe how the company forecasted project-level detail for the second and third years of the 2022 SPP.

Q. In his direct testimony, Mr. Pickles states that Tampa Electric used a consultant to assist with the development of the 2022 SPP. Why did Tampa Electric use this consultant?

A. Tampa Electric hired the same consulting firm (1898 & Co.) that helped with the development of the company's 2020-2029 Storm Protection Plan. Tampa Electric hired the consultant to provide an independent, third-party review of the company's SPP programs and to reevaluate the company's methodology and prioritization approach. In addition, Tampa Electric used 1898 & Co.'s model for cost-benefit analysis. The consultant's model gave us the capability to perform an updated 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 to incorporate the lessons learned from the initial implementation of the programs and supporting projects of the company's 2020-2029 SPP. The consultant's model prioritized the projects within each of the programs outlined above and analyzed the costs and benefits of the programs. In addition, the consultant gave the company the ability to model the combined improvements from multiple programs simultaneously, model multiple scenarios, optimize portfolio spending, and confirm that modelled benefits were appropriate, achievable, and in range with the industry. The prepared direct testimony of Jason D. De Stigter from 1898 & Co., filed contemporaneously in this docket, more fully details the approach taken for each of these programs.

Q. Please explain how Tampa Electric and 1898 & Co. estimated 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. Mr. De Stigter explains the methodology used to estimate the reduction in outage times and restoration costs in detail. In general, 1898 & Co. developed a storm resilience model that simulated 99 different storm scenarios, and each scenario identified which parts of the electric system are most likely to fail. 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 & Co.'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. Next, the model calculated the benefit of decreased restoration cost and reduced CMI if that hardening project were implemented per the company's hardening standards. This approach was repeated for every potential hardening 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 2022 SPP 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 program. These estimates are included in my Exhibit No. DLP-1, Document No. 1 and are represented in terms of the relative benefit or improvement that the 2022 SPP 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 prioritize projects in these programs is described in detail by Mr. De Stigter. In general, we developed a project cost estimate for each potential project, based on several factors depending on the program. For example, for distribution lateral undergrounding, we considered factors such as the length of the total lateral line and location of the facilities (front or rear lot). Next, 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 CMI. We converted the outage time reductions or savings to financial benefits using 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. We combined both benefits, avoided restoration costs and monetized customer outages, and calculated a cost benefit Net Present Value ("NPV") ratio for each potential project. We used the NPV ratios to prioritize each project within a given SPP program.

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

A. No. The ranking serves as a guide, but the company also applied operational experience and judgment when selecting projects. The company considered things like ensuring that all areas and communities are represented equitably within our service territory and ensuring that critical customers are appropriately considered in setting the final ranking.

Q. Does the number of projects listed in your 2022 SPP for the year 2022 match the count of projects for 2022 that will be listed in your filings in the Storm Protection Plan Cost Recovery Clause?

A. No. The company developed a list of projects in late 2021 to evaluate for inclusion in the 2022 SPP. At that time, the company believed that some projects that were underway in 2021 would be completed by the end of the calendar year. These projects were accordingly excluded from the 2022 SPP and its supporting analyses. Some of these projects, however, were not completed in 2021. As a result, the project count for 2022 in the Storm Protection Plan Cost Recovery Clause filings is slightly higher than the project count in the 2022 SPP.

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 & Co.'s model to compare its performance before and after hardening. The benefits of a reduction in restoration costs and outage times for all 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. DLP-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 the 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 provided in Mr. De Stigter's direct testimony. In general, we calculated a cost benefit NPV ratio for each potential project and used it to first determine projects' relative cost-effectiveness and then to prioritize projects within each of the programs. As I mentioned earlier, we established a ranked project listing that the company will use, along with business and operational judgement, to determine when projects will be implemented. Then we aggregated the estimated costs and benefits for all projects selected for each program during the ten-year 2022 SPP period to determine the total costs and benefits of each program illustrated in my Exhibit No. DLP-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 facilities. Tampa Electric has approximately 6,235 miles of overhead distribution lines, of which approximately 4,441 miles or 71 percent 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. How are projects prioritized under this program?

A. As described further in the Storm Protection Plan and in the direct testimony of Mr. De Stigter, the company worked with 1898 & Co. to prioritize all lateral lines based on the cost-benefit NPV ratio for each project. We factored in the avoided probability or likelihood of failure and the impact in terms of restoration costs and customer outages if a failure occurs during a major weather event.

Q. Did Tampa Electric learn any lessons from the initial implementation of this program under the prior SPP?

A. Yes. Mr. Pickles describes several lessons learned in his direct testimony. In addition to these lessons, the company also learned that there is a more efficient way to prioritize and implement undergrounding projects.

Under the prior plan, Tampa Electric evaluated each distribution line segment between protection devices individually, which meant that one lateral would be broken up into any number of potential projects. The company discovered through implementation that this methodology, while still effective and beneficial, is not the optimal method for prioritizing and planning projects.

Q. How did Tampa Electric's prioritization methodology change from the company's prior SPP for this program?

A. The company still uses the cost-benefit NPV ratio for prioritizing projects. However, the definition of a project has changed. The company now evaluates some electrically connected distribution lateral segments served by the same feeder together to improve design, communication and construction efficiency, and customer satisfaction. This method has several benefits. First and foremost, the design and customer outreach process for full laterals allows clearer communication to customers and enables broader support than doing piecemeal projects. Secondly, the design of a single larger footprint allows for more efficient looping, than looping each small section. Lastly, the mobilization and demobilization of resources in a larger but related footprint is more efficient than completing a small project and returning in the future for another small project.

Q. Is the company changing the way this program is facilitated?

A. Yes. Mr. Pickles explains how the company is proposing changes related to use of public right-of-way and the project permitting process based on lessons learned from implementation of the prior plan.

Over the past two years the company has been ramping up overhead to underground conversion projects and supporting processes to maintain momentum as this program will continue past the ten-year horizon of this 2022 SPP. The company’s projected 75 to 100 miles of annual distribution lateral undergrounding is the same that was approved in Tampa Electric’s initial SPP.

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

A. Community and customer outreach is critical to the success of this program. The company has placed a significant emphasis on this and has implemented staffing to ensure the community and customer outreach is customer supportive, comprehensive, and effective. Tampa Electric is currently working on creating more educational media to help customers, property owners, and neighborhoods understand the steps necessary to convert their overhead service to underground service, and the company has been working to improve the success rate of obtaining easement agreements from customers. The company has also learned that customers generally prefer for undergrounded laterals to be in existing right-of-way, so the company now initially designs projects with this in mind where it is practical to do so.

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

A. The Distribution Lateral Undergrounding Program provides 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 on the company's distribution system originate from an event on an overhead distribution lateral line. In addition, a significant amount of a utility's restoration efforts address 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 proximity to 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 create the most significant impact during a major storm event. Comparatively very few, if any, outages originated on underground facilities during the recently experienced named storms and only six percent during blue sky, day-to-day conditions. By undergrounding these overhead lateral lines, the risk of failure during a major storm event will be significantly mitigated.

Q. Did Tampa Electric prepare a list of Distribution Lateral Undergrounding projects that the company is planning on initiating in 2022, including their associated starting and projected completion dates?

A. Yes, we included the list of Distribution Lateral Undergrounding projects for 2022 and their associated starting and projected completion dates in Appendix A of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 2. The company also developed a preliminary list of projects for 2023.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project, including the number and type of customers served?

A. Yes, I provide a description of facilities affected by project in my Exhibit No. DLP-1, Document No. 2. For this SPP program, Tampa Electric will continue to 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 developed cost estimates for each project within this program for 2022, 2023, and 2024 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, for example, the number of phases involved, the length of the line, and the location of the facilities (front or rear lot). Based on the results of 1898 & Co.'s budget optimization model, the company then estimated the number of projects it expects to complete in years 2025-2031 with average project cost estimates to develop the annual program costs in those years. The estimated capital costs for this program are $106 million in 2022, $105 million in 2023, $105 million in 2024, and approximately $105 million to $115 million each year during the period 2025 through 2031. The estimated O&M costs for this program include $0.18 million in 2022, $0.18 million in 2023, $0.18 million in 2024, and approximately $0.15 million to $0.33 million each year from 2025 through 2031. The table below sets out the estimated number of projects and annual costs for 2022 through 2024.

	Tampa Electric's Distribution Lateral Undergrounding Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	646	$105.8
2023	399	$104.7
2024	436	$105.2

VEGETATION MANAGEMENT

Q. What are the components of the proposed Vegetation Management Program ("VMP") in the company's 2022 SPP?

A. For purposes of its 2022 SPP, the company's VMP consists of four parts. The company's four Vegetation Management ("VM") initiatives are described below.

Distribution and Transmission VM: Tampa Electric's VMP calls for trimming the company's distribution system on a four-year cycle. The company's maintains the 138kV and 230kV bulk transmission lines on a two-year cycle and the 69kV and 34kV lines on a three-year cycle. Distribution and Transmission VM includes planned and unplanned (reactive) trimming.

Supplemental Distribution VM: Supplemental Distribution Circuit VM increases the volume of full circuit maintenance performed on an annual basis.

Mid-cycle Distribution VM: Mid-cycle Distribution VM is an inspection-driven, site-specific approach designed to target vegetation that cannot be effectively maintained by cycle trimming. This initiative also targets hazard trees.

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

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

A. The company received approval from the Commission in Order No. PSC 12-0303-PAA-EI, issued June 12, 2012, in Docket No. 20120038-EI, 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 maintains the 138kV and 230kV bulk transmission lines on a two-year cycle and the 69kV and 34 kV lines on a three-year cycle. We manage transmission circuits on a ‘strict’ or ‘hard’ cycle. Although strict, the schedule allows adequate flexibility to accommodate new or redesigned circuits. We manage all circuits above 200kV 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, 250 non-bulk miles and 280 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 a reliability-based and a cost-effective 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 280 tree trim personnel dedicated to distribution and transmission planned VM. The company has a total of 331 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 the ANSI pruning guidelines?

A. The ANSI uses industry research to generate a set of guidelines for a variety of industry practices. The ANSI A300 guidelines help arborists determine the way vegetation should be trimmed to achieve desired objectives while preserving tree health and structure. The ANSI Z133 guidelines help arborists and non-arborists follow safe work practices.

Q. How did the company analyze the costs and benefits of the incremental vegetation management activities?

A. Tampa Electric used a consultant to determine the costs and benefits of the three incremental VM activities when it developed the initial SPP that was filed on April 10, 2020.

Q. Did the company update this information for the 2022 SPP that was filed in this proceeding?

A. No. Tampa Electric believes that the scenarios and associated cost-effective results and priorities of the study performed to support the SPP filed on April 10, 2020 are still valid. This study is included in my Exhibit No. DLP-1, Document No. 3.

Q. How many incremental miles of distribution and transmission overhead facilities does Tampa Electric plan to trim over the first three years of the 2022 Plan?

A. For the first three years, the company plans to trim approximately 2,090 additional miles of distribution lines and an additional 75 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 2,210 miles in the first three years of the 2022 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 2022 SPP?

A. The company plans to trim approximately 4,680 miles of distribution facilities under the baseline cycle and 2,090 miles under the Supplemental Trimming Initiative. We also plan to inspect 2,210 miles under the Mid-Cycle Initiative, for a total of approximately 8,980 miles of distribution trimming. The company plans to trim approximately 1,590 miles of transmission facilities under the baseline cycle, plus an additional 75 miles under the 69kV Reclamation Initiative, for a total of approximately 1,665 miles of transmission facility trimming.

Q. What are the estimated annual labor and equipment costs for the VMP during the first three years of the 2022 SPP?

A. The estimated annual labor and equipment costs for the first three years of the 2022 SPP total $83.9 million. The four-year distribution cycle labor and equipment costs for the first three years are $38.3 million, and the incremental distribution VM labor and equipment costs are $31.1 million. The first three years of transmission cycle labor and equipment costs are $8.9 million, and the incremental transmission VM labor and equipment costs are $1.4 million. The first three years of unplanned VM labor and equipment costs are $4.2 million. The total cost for the program is set out in Section 6.2 of the company’s 2022 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 that was performed, Tampa Electric determined that the 26 percent improvement in storm restoration time and cost are worth the estimated

$10.7 million annual average increase in distribution VM O&M expenses. In addition, the benefits associated with reduced restoration time and cost and lessened vegetation contact potential clearly show that the 69kV reclamation project additional annual expense is a tremendous value for Tampa Electric customers.

The table below provides the annual costs for VM activities for 2022 through 2024.

	Tampa Electric's Vegetation Management Program Projected Costs (in thousands)		
	2022	2023	2024
Supplemental Vegetation Management Project Costs	$6,100	$7,100	$4,800
Mid-Cycle Vegetation Management Project Costs	$3,500	$4,000	$5,600
69 kV Reclamation	$695	$695	$0
Planned Distribution	$11,561	$12,901	$13,823
Planned Transmission	$2,917	$2,966	$3,035
Unplanned	$1,400	$1,400	$1,400
Total	$26,173	$29,062	$28,658

TRANSMISSION ASSET UPGRADES

Q. Please provide a description of the Transmission Asset Upgrades program.

A. The main objective of the Transmission Asset Upgrades program is to address the vulnerability that the company's remaining wood transmission poles pose 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 by December 31, 2029. The company has identified 126 of its existing 225 transmission circuits that have at least one wooden pole and will replace 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 1,300 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. Most of these pole failures are associated with wood poles. Of the 10 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 previous Storm Hardening Plan Initiative. The company has 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. As of January 1, 2022, approximately 84 percent of Tampa Electric's transmission system is constructed of steel or concrete poles/structures. The remaining 16 percent, however, are wood poles installed over 30 years ago. Replacing the remaining wood transmission poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, more robust wind loading standards than those required at the time of installation. This will greatly reduce the likelihood of a failure during a major storm event.

Q. Is Tampa Electric proposing any changes to the existing Transmission Asset program?

A. No, the company is not proposing any changes to the Transmission Asset program and remains on track for replacing the remaining wood transmission wood poles with non-wood material by the end of 2029.

Q. Did Tampa Electric prepare a list of Transmission Asset Upgrades projects that the company is planning on initiating in 2022, including their associated starting and projected completion dates?

A. Yes, we included the list of Transmission Asset Upgrades projects for 2022 and their associated starting and projected completion dates in Appendix C of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 4. The company plans 37 projects for 2022 and identified a preliminary list of 26 projects for 2023 and 10 projects for 2024. The remaining transmission circuits with wood poles are scheduled for upgrade in the years 2025 through 2029.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project, including the number and type of customers served?

A. Yes. I provide a description of the affected facilities for each Transmission Asset Upgrades project in my Exhibit No. DLP-1, Document No. 4. The description includes 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 developed cost estimates for each project within this program for 2022, 2023, and 2024 and totaled those estimates to derive the annual cost estimates for the program. The company used 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 2024 through 2029 with average project cost estimates to develop the annual program costs in those years. The estimated capital costs for this program are \$16.5 million in 2022, \$17.5 million in 2023, \$17.5 million in 2024, and approximately \$17.5 million in each year during the period 2025 through 2029. The incremental annual O&M costs associated with this program are approximately \$0.5 million. The table below sets out the estimated number of projects and estimated annual costs for this program for 2022 through 2024.

	Tampa Electric's Transmission Asset Upgrades Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	37	$17.0
2023	26	$18.0
2024	10	$18.1

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. The program minimizes outages, reduces restoration times, and enhances emergency response during extreme weather events. In its prior SPP, the company identified 59 of its 216 substations that have risk due to flood or surge. 1898 & Co. modeled these 59 substations and prioritized them based on the expected benefits of mitigation after hardening with a flood wall solution and selected 11 substation hardening projects for the 2022 SPP. 1898 & Co.'s model indicated that the substation hardening projects accounted for a sizable restoration benefit while requiring a small percentage of the prior SPP capital investment. Given this dramatic benefit to cost ratio, the company decided that further evaluation and assessment of this program is needed. In March 2021, the company obtained the assistance of a third-party engineering firm to perform a study to evaluate various substation hardening solutions and assess the potential vulnerability of the identified substations to extreme weather, including flooding or storm surge.

Q. What were the results of the Substation Hardening Study?

A. The Substation Hardening Study evaluated 24 coastal substations that are a mix of Transmission and Distribution Substations that serve as switching stations to distribute large generation resources. Each of the 24 substations results was reviewed for its susceptibility to storm surge flooding, in addition to those substations which would have the greatest impact on grid stability, reliability of service, safety, and environmental risks if an extended outage from an extreme weather event occurred. The Substation Hardening Study recommended nine specific substation projects to be initiated for the company’s 2022 SPP. I provide the Substation Hardening Study in my Exhibit No. DLP-1, Document No. 5.

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 increases the resiliency and reliability of the substations using permanent or temporary barriers, elevating substation equipment, or relocating facilities to areas that are less prone to flooding. For the substations located closest to the coastline and at greatest risk, substation hardening efforts 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 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. As we developed the substation hardening projects, we also created budgetary cost estimates for the projects. The cost estimates are for turnkey construction, including engineering, equipment, construction, testing, and commissioning. These costs were used in a cost-benefit analysis to determine the project impact in improving grid resiliency and its cost-effectiveness.

Q. Did Tampa Electric prepare a list of Substation Extreme Weather Hardening projects that the company is planning on initiating in 2022, including their associated starting and projected completion dates?

A. The company does not propose initiating any Substation Extreme Weather Hardening projects for 2022.

Q. Is Tampa Electric proposing any changes to the existing Substation Extreme Weather Hardening program?

A. Yes, the company is proposing to start work on substation extreme weather capital projects in the latter part of 2023, as compared to a start date in 2024 in the company's prior SPP. All other aspects of this proposed 2022-2031 Substation Extreme Weather Hardening program are identical to those of the program in the prior SPP.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project, including the number and type of customers served?

A. Yes. I provide a description of the facilities that will be affected by each project, including the number and type of customers served, in my Exhibit No. DLP-1, Document No. 6.

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. Yes. The company prepared 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, and it is included in my Exhibit No. DLP-1, Document No. 6.

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

A. Yes. The company developed cost estimates for each project within this program for 2022, 2023, and 2024 and totaled those estimates to derive the annual cost estimates for the program. As I previously stated, the costs for each of the substation extreme weather hardening projects were developed in the substation hardening study. The estimated capital costs for this program are $0.0 million in 2022, $0.7 million in 2023, and $4.3 million in 2024. There are no estimated incremental O&M costs for this program at this time. The table below sets out the estimated number of projects and annual costs for 2022 through 2024.

	Tampa Electric's Substation Extreme Weather Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	0	$0.0
2023	1	$0.7
2024	1	$4.3

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 lines, 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 once it leaves the substation. This SPP program will continue to expand efforts to harden and protect some of the company’s highest priority feeders, starting with those that have the worst historical day-to-day performance and performance during major storm events, the highest likelihood of failure, and 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 enhances 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. The implementation includes installing stronger hardened poles and facilities; installation of switching equipment to allow automatic isolation of damaged facilities; upgrading 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.

In addition, we will upgrade feeder conductors, install sectionalizing switching devices and fault current indicators, and create circuit ties to allow automation and

SCADA control. These steps harden the feeders and reduce restoration times.

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. We will harden these feeders by upgrading poles smaller than class 2 and ensuring the feeders meet National Electric Safety Code ("NESC") extreme wind loading standards to increase the overall resiliency of the feeder. In addition, certain poles are designated as "Critical Poles" that have critical equipment such as reclosers or capacitor banks, and that are critical locations on the system, such as terminations, and 3-phase laterals. For these "Critical Poles" we will use even stronger poles (class 1 wood or class H! concrete).

Q. Is Tampa Electric proposing any changes to the existing Overhead Feeder Hardening program?

A. Yes. The company includes all components of the existing Commission-approved Overhead Feeder Hardening program and adds three applications to leverage the data of the company's advanced metering infrastructure system to prevent outages during extreme weather events, reduce the length of outages during extreme weather events, and reduce the amount spent on extreme weather restoration. They include the following applications.

Locational Awareness: determines the electrical connectivity above the meter within the distribution grid and provides the ability to accurately assess the connectivity of the system, from the meter to the transformer, transformer to the feeder, and the phase connectivity which will increase the opportunity for quicker restoration during extreme weather events.

Vegetation Contact Detection: identifies feeder sections that have repeated vegetation contact, indicating that vegetation management should be prioritized to those areas to minimize customer interruptions and the likelihood of damage caused by vegetation during extreme weather events.

Storm Mode: is a mechanism for maximizing outage and restoration reporting performance during widescale outages by minimizing and prioritizing outage and restoration messages. Storm mode provides faster and more accurate indication of feeder and feeder section energized state during widescale outages.

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 the feeder, 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 2022, including their associated starting and projected completion dates?

A. Yes. We include the list of Distribution Overhead Feeder Hardening projects for 2022 and their associated starting and projected completion dates in Appendix D of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 7. The company has a preliminary list of projects for 2023 and 2024 and has identified how many distribution feeders the company plans to harden in the years 2025 through 2031.

Q. Did Tampa Electric prepare a description of the facilities that will be affected by each project including the number and type of customers served?

A. Yes. We show in Appendix D of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 7, the description of facilities affected, including 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 developed cost estimates for each project within this program for 2022 through 2024 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. The estimated costs for each project reflect bringing that feeder 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 on laterals, feeder segmented and automated with no more than 200 to 400 customers per section, and no segment longer than two to three miles, no more than two to three MW 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 2024 through 2031 with average project cost estimates to develop the annual program costs in those years. The estimated capital costs for this program are $32.8 million in 2022, $30.1 million in 2023, and $30.0 million in 2024. There are approximately $0.6 million in incremental annual O&M costs associated with this program. The table below includes the estimated number of projects and estimated costs per year for 2022 through 2024.

	Tampa Electric's Distribution Overhead Feeder Hardening Program Projects by Year and Projected Costs (in millions)	
	Projects	Costs
2022	36	$33.4
2023	31	$30.7
2024	23	$30.7

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.

Q. Is Tampa Electric proposing any changes to the existing Transmission Access program?

A. Yes. The company is keeping all the components of the existing Commission-approved Transmission Access program, but the company is proposing that this program should be structured with no end date to facilitate projects as needed in the future.

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 more timely storm restoration.

Q. How did the company analyze the costs and benefits of the transmission access program?

A. Tampa Electric used a consultant in the prior SPP, filed on April 10, 2020, to determine the costs and benefits of the transmission access program projects that the company is currently performing or planning to perform in the future.

Q. Did the company update this information for the 2022 SPP?

A. Yes. The company made a slight modification to the list of Transmission Access projects based upon further internal evaluation.

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. Mr. De Stigter describes the methodology used to develop the estimate of the reduction in outage times and restoration costs in detail. In general, 1898 & Co. developed a model that calculates the benefit in terms of decreased restoration cost and reduced 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 2022-2031 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	$31.5	$0.0	28	55	Q1 2021	After 2031

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

A. Mr. De Stigter describes the methodology used to develop the prioritization of projects in these programs in detail. In general, the company and 1898 & Co. developed a potential cost estimate and estimated benefits for each potential project. The estimated benefits include reduced CMI and reduced restoration costs. We combined the benefits and calculated a cost-benefit NPV ratio for each potential project. We used the NPV ratios to prioritize each project within the program. The rankings serve as a guide, and the company also applies operational experience and judgment when selecting projects.

Q. Did Tampa Electric prepare an estimated number of Transmission Access projects it plans on initiating in 2022 through 2024?

A. Yes. Using the analysis provided by 1898 & Co., the company prioritized a list of 48 projects it plans to begin in 2022, 2023, and 2024. We include the list of Transmission Access projects for 2022 and their associated starting and projected completion dates in Appendix E of the 2022 SPP and in my Exhibit No. DLP-1, Document No. 8.

Q. Did Tampa Electric prepare an estimate of the costs for the projects planned for 2022 through 2024?

A. Yes. The company estimates the capital costs to be $2.4 million in 2022, $3.0 million in 2023, and $3.0 million in 2024. There are no estimated incremental O&M costs for this program. 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
2022	25	$2.4
2023	25	$3.0
2024	13	$3.0

Q. Did Tampa Electric prepare individual cost estimates for this program, including capital and operating expenses for access roads and access bridges?

A. Yes, the table below sets out the estimated costs for the program by year over the ten-year plan horizon, showing the access roads and access bridges portions.

	Total Transmission Access Enhancements Program Costs (in thousands)		
	Access Road Projects Costs	**Access Bridge Project Costs**	**Total Transmission Access Project Costs**
2022	$724	$1,686	$2,410
2023	$879	$2,158	$3,037
2024	$1,844	$1,163	$3,007
2025	$1,614	$2,089	$3,703
2026	$2,838	$608	$3,447
2027	$3,404	$0	$3,404
2028	$1,932	$1,211	$3,142
2029	$1,167	$1,672	$2,839
2030	$997	$1,043	$2,041
2031	$4,425	$0	$4,425

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 resilient to 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 NESC strength requirements. Tampa Electric performs inspections of all wood poles on an eight-year cycle. Tampa Electric has approximately 285,000 wooden distribution and lighting poles and 26,000 transmission poles and structures that are part of the 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, or reconfigured circuits.

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 allow for periodic inspections and audits of 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 a high probability that the equipment attached to the pole also will be damaged. Cascading failures of other poles are also likely to occur. Specifically, wood poles pose the greatest risk of failure and must be maintained and eventually replaced given they are prone to deterioration. The eight-year wood pole inspection requirement put in place by the Florida Public Service Commission is aimed at identifying any problems with a pole so it can be mitigated before it causes a problem during a major storm event. In addition, the other FPSC required inspections included in this SPP program are aimed at identifying equipment issues that are compromised and 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 are 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 2022, 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 2022 through 2024, along with the estimated cost. The table 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			
	2022	**2023**	**2024**
Joint Use Audit	Note 1		
Distribution			
Wood Pole Inspections	35,625	35,625	16,625
Transmission			
Wood Pole/Groundline Inspections	663	479	401
Above Ground Inspections	3,386	2,641	2,702
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 customers served?

A. As I previously mentioned, Tampa Electric conducts thousands of inspections each year, and we did not identify specific projects or affected facilities. The company identified the number of inspections by type planned for 2022 through 2024. 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 the projects the company is including in this Infrastructure Inspections program?

A. Tampa Electric typically prioritizes its inspections by age or date of last inspection. We also consider the following criteria:

- 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
- aerial infrared scans are scheduled in the summertime 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. The estimated costs for this program include $1.6 million in 2022, $1.5 million in 2023, $1.6 million in 2024, and approximately $1.8 million in each year from 2025 through 2031. All costs associated with this program are O&M and are summarized in the following table.

Projected Costs of Infrastructure Inspections (in thousands)			
	2022	**2023**	**2024**
Distribution			
Wood Pole Inspections	$1,020	$1,040	$1,061
Transmission			
Wood Pole/Groundline Inspections	$62	$64	$65
Above Ground Inspections	$10	$11	$11
Aerial Infrared Patrols	$114	$117	$119
Ground Patrols	$201	$154	$157
Substation Inspections	$146	$146	$148

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 storm protection activities that are referred to 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 the 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, 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 mentioned, all 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 2022 through 2024 period. Tampa Electric plans to invest $12.5 million in 2022, $12.98 million in 2023, and $13.3 million in 2024 of capital for distribution pole replacements. There is an associated operating expense of $0.8 million in 2022, $0.8 million in 2023, and $0.9 million in 2024 for this activity. In addition, the company plans to incur approximately $0.3 million per year during 2022 through 2024 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
2022	$0.3	$13.3
2023	$0.3	$13.7
2024	$0.3	$14.1

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

Q. Does Tampa Electric's 2022 SPP 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 2022 SPP includes the required program-level detail for the eight storm protection programs described in my testimony. The 2022 SPP also includes the necessary project-level detail for the programs that contain SPP projects.

CONCLUSIONS

Q. Please summarize your direct testimony.

A. My testimony demonstrates that the programs I discussed in Tampa Electric's proposed 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, Vegetation Management, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder Hardening, Transmission Access, Infrastructure Inspections, and Legacy Storm Hardening programs be approved?

A. Yes. These programs should be approved. The 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.

BY MR. MEANS:

Q Mr. Plusquellic, did you include an exhibit labeled DLP-1 consisting of eight documents with your direct prefiled testimony?

A I did.

MR. MEANS: Mr. Chairman, we would like to note this is on staff's comprehensive exhibit list as Exhibit 11.

CHAIRMAN FAY: Great.

BY MR. MEANS:

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

A I did.

Q Could you please read us that summary?

A Sure.

Good afternoon. My direct testimony addresses the rigorous and comprehensive process that Tampa Electric followed to develop our 2022 to 2031 storm protection plan. We started that process just a few months after our first SPP was approved. We spent time over about a 16-month period developing this plan, even though it predominantly consists of the eight programs that were improved -- I am sorry, that were approved in the original 2020 plan with some minor modifications.

My testimony describes the process we used to develop that plan, as well as the plans and the prioritizations at the program and project level. The company took great efforts by deploying a variety of tools and analyses that are included in our plan. We engaged industry specialists, internal experts to the company, and ultimately worked very hard to strike a balance between customer rate impact, costs, benefits, restoration, cost reduction, outage minute reductions and the impact of the plan on customers' bills, as well as some of the other indirect benefits to customers in the broader community.

Again, the company's plan is a continuation of the eight plans that were originally in our 2020 plan. My testimony demonstrates that all of the company's storm protection programs 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 to meet the requirements of the Commission's Rule 25-6.030.

In conclusion, my testimony provides support for the approval of Tampa Electric's proposed 2022 to 2031 storm protection plan.

Thank you.

MR. MEANS: Mr. Chairman, we tender the

witness for cross.

CHAIRMAN FAY: Great. Thank you.

Ms. Wessling, you are recognized.

MS. WESSLING: Thank you.

EXAMINATION

BY MS. WESSLING:

Q And good afternoon.

A Hi.

Q Hi there.

So I suppose we will start with the transmission access program. I believe you are discussing that on page 45 of your testimony, if you want to go there.

A I am there.

Q All right. Are you familiar with the NERC standard TPL-002-2B system performance following loss of a single BES element that requires transmission systems to be designed for a single contingency outage?

A I am not personally. No.

Q Do you know if TECO's system is designed for a single contingency outage?

A I don't know that detail. I am confident in our transmission planning organization, that they meet or exceed all existing requirements.

Q Okay. So if that was a requirement, you are

confident that TECO is in compliance with that requirement?

A Subject to check, yes.

Q Okay. With regard to the transmission access program, the infrastructure -- let me back up.

The transmission access program you propose, or you are requesting funding for the certain access roads and access bridges, correct?

A Yes.

Q All right. And as of now, before any of that is approved or constructed, is the infrastructure on the other side of those bridges, or the end of those roads, currently in good condition?

A Currently in what? I am sorry.

Q Currently in good condition.

A For the access roads portion, we have no permanent consistent access. So after extreme weather events, it could be soft soil. It could be flooded. It could be wet, difficult to traverse.

And I don't remember the numbers. They are in the plan. But there are what you might call bridges in some of the locations that we are proposing to put more modern, hardened bridges in place. So in those cases, we have challenging or no access at all right now.

Q Even on a blue sky day, you have challenging

or poor access, is that what you just said?

A Even on a blue sky day, in many of these locations, we do have challenges. Yes.

Q Okay. And the roads and bridges that we have been discussing, those are used throughout the year for -- in order to conduct inspections, maintenance and replacement activities, correct?

A I can't speak to all cases. So if it's a normal routine maintenance, where time is not, you know, one of the critical elements, you might take a longer route. You might have time to request access from a customer from, you know, from a different avenue.

If it has rained, you might be able to postpone your inspection until next week, until the soil has dried out. But in some cases, you know, we do currently have access as well.

Q Okay. And I would like to go to page 47 of the actual storm protection plan, which is Exhibit DAP-1. Do you have a copy of that?

A I do.

Q Okay.

A What page? I am sorry.

Q Page 47 of 78.

A Okay.

Q All right. So where it says access roads in

bold --

A Uh-huh.

Q -- would you read the first sentence, please?

A These projects are designed to restore access to areas where changes in topography and hydrology have negatively impacted existing access roads or created the need to establish new access roads.

Q So this goes back to my question earlier, but this says that -- this implies, anyway, that there are areas that Tampa currently does not have access to and needs to restore access to?

A Uh-huh.

Q And there is transmission -- there is assets, again, in these locations that Tampa needs to restore access to and they can't currently access?

A We have many areas where we can access them, but we have access challenges. For example, we don't have permanent roads in many of those locations. I have personally driven some of them where the straightest path to the transmission assets is extremely challenging, where if you could put in a permanent road, you could mitigate those circumstances where you wouldn't have to take, you know, maybe a much longer route to get there.

So we have access at some level to all of our assets, just not easy and timely access in all cases, and not permanent access. In some cases, we have to put matting down or, you know, make other temporary arrangements to get access.

Q But you do access them ultimately?

A We do, yes. Sometimes it may only be, you know, through a pickup truck, or a small type of truck where, for example, these bridges are designed to be -- to handle 72 tons. So we would be able to very quickly get cranes and big equipment to restore towers, for example. We don't have that type of access consistently right now.

Q And if these roads and bridges were approved in the plan, would you only use those roads and bridges during extreme weather?

A No.

Q So you would also use them to perform normal business operations throughout the year, even on blue sky days?

A Sure.

Q If we could go to page -- the next page, page 49 of 78. There is bold the access bridges wording. But could you read the last sentence of that paragraph for me, that begins on -- there is no line numbers, but it begins with the access bridge?

A The last sentence of the big paragraph?

Q Yes.

A The access bridge project will bring the bridges up to capacity to meet the current weight of the company's transmission vehicles and secure pilings and positions -- position in and over the waterways to ensure constant access to critical transmission infrastructure, particularly during extreme weather events.

Q So that says particularly during extreme weather events, right?

A Yes.

Q Not exclusively?

A Correct.

Q All right. And you would agree that maintenance and inspection of Tampa's infrastructure is part of the day-to-day operations of Tampa Electric, correct?

A Yeah. I am not an attorney, but I will say yes.

Q Correct. Yeah. I don't think you need to be an attorney for that one.

You would agree with me that conductors break, insulators break and structures break even in the absence of extreme weather, correct?

A On the transmission system, hopefully not very often, but yes, it happens.

Q Okay. If that happens on infrastructure that's accessed by these new roads and bridges, Tampa would use those new roads and bridges to fix things like that too, correct?

A Correct.

Q With regard to TECO's distribution feeders sectionalizing and automation project, it uses communication between devices in an operations center to allow the distribution network to be reconfigured automatically, correct?

A Yes.

Q Right. Is it correct to characterize that as a fault isolation system?

A Yes.

Q Does this work on a radial feeder or on only on a feeder that's tied to adjacent feeders?

A I am not an engineer. I am going to go largely off of what Witness DeStigter said and described. There has -- in order to switch from one feeder to another, clearly you have to be connected. But the term radial I am not positive on.

Q Okay. During an extreme weather event, if a pole fails from wind or due to a fallen tree, the cost

to replace the pole is the time for the line crew to get to the site and make the repairs, correct?

A I apologize, can you ask one more time?

Q Sure.

During an extreme weather event, if a pole fails from wind or from a tree, the cost to replace that pole is the time for the line crew to get to the site and make the repairs, is that correct?

A Yes, except the pole, the material.

Q Plus the pole?

A Yeah.

Q Okay. If the pole -- and you may or may not be able to answer this, but if this pole failure is isolated by a new recloser, does the cost of replacing that pole change?

A No.

Q And again, I believe the exhibits from earlier are to your -- that side of you. If you could look at what's in evidence as Exhibit 81. It's also the title -- it's also titled as Tampa Electric's Responses to OPC's Second Set of Interrogatories.

A I apologize, where is 81?

Q Sorry. It probably doesn't have 81 on it, but the description says, on the front page, says, TECO's Responses to OPC's Second Set of Interrogatories.

A I got it. Thank you.
Q Okay. Great.
You assisted in the preparation of some of these interrogatories, correct?
A Yes.
Q All right. And that includes interrogatory number 40, which is on page, looks like page, Bates page 56.
A Yes.
Q So that is one that you --
A Yes.
Q -- sponsored? Okay.
And in that response, you state that specific rate impacts were calculated after the company decided on an overall level of investment for the plan, correct?
A That's in this response?
Q Yes. You can look for it, and I can say it again if you would like. I believe it's in the second sentence.
A Yes. The statement says that. And one item I would point out is it's specific rate impacts. So from the very beginning of our planning process, we were, you know, very aware of the customer rate impact of our plans, specifically for '23 to -- I am sorry, '22 to '31. Our proposed investment levels are essentially in

line with our prior plan, where those rate impacts were calculated. So we were -- we were very aware of what that potential rate impact would be. So I think the key word in this sentence is the specific rate impact.

So, you know, during planning, we may not have gone to four decimal points, for example, where, you know, Mr. Latta, in his calculation, probably, you know, probably did. So that's the distinction I would draw.

MS. WESSLING: Nothing further.

CHAIRMAN FAY: Great. Thank you.

Next, Mr. Moyle.

MR. MOYLE: No questions.

CHAIRMAN FAY: Okay.

MS. EATON: No questions.

CHAIRMAN FAY: Okay. Staff.

MR. IMIG: No questions.

CHAIRMAN FAY: Okay. Commissioners?

Seeing none. Redirect?

MR. MEANS: Thank you, Mr. Chairman.

FURTHER EXAMINATION

BY MR. MEANS:

Q Mr. Plusquellic, I just want to follow up a little bit on the transmission questions.

So Tampa Electric does have access to its transmission right-of-way in some locations, is that

correct?

A We are currently required to access all of our -- all of our systems. So, yeah, we have some level of access. Some is easier and some is more difficult, yes.

Q Okay. Thank you.

MR. MEANS: No further questions.

CHAIRMAN FAY: Great. Thank you.

Enter the exhibit?

MR. MEANS: Yes, please. We would like to enter the exhibit into the record.

CHAIRMAN FAY: Okay. Without objection, show Exhibit 11 entered into the record.

(Whereupon, Exhibit No. 11 was received into evidence.)

CHAIRMAN FAY: With that, Mr. Plusquellic, you are dismissed.

(Transcript continues in sequence in Volume 4.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

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

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

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

DATED this 11th day of August, 2022.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024