BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210034-EI

Petition for rate increase by
Tampa Electric Company.
__________________________________/

DOCKET NO. 20200264-EI

Petition for approval of 2020
depreciation and dismantlement study
and capital recovery schedules, by
Tampa Electric Company.
__________________________________/

VOLUME 2
PAGES 232 - 482

PROCEEDINGS: HEARING

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

DATE: Thursday, October 21, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 10:24 a.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

I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

(Whereupon, prefiled direct testimony of Melissa L. Cosby was inserted.)

ERRATA SHEET

DIRECT TESTIMONY OF MELISSA L. COSBY[1]

Page and Line	Original Text	Change
34:6	53 percent	57 percent
34:7	534	561
	252	243

[1] Document No. 03305-2021, filed April 9, 2021 in Docket No. 20210034-EI.

TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

MELISSA L. COSBY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MELISSA L. COSBY

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

A. My name is Melissa Cosby. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Director, Customer Experience Strategy and Service Excellence.

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

A. I am responsible for leading Tampa Electric's customer experience strategy and providing support to our customer experience operations. My responsibilities include ensuring the company understands customers' evolving expectations for electric services and developing and implementing a strategy and plan to stay relevant with advancing technology and evolving customer expectations and provide excellent service to our customers. I am also responsible for our Voice of the Customer program, which focuses on gaining insight into customers' wants, needs, perceptions, preferences, and expectations. These insights and feedback are used to make business decisions to improve the customer experience.

Additionally, my responsibilities include workforce management, administrative services, customer complaint management, quality monitoring for the customer contact centers, customer experience training, and management of the customer experience project portfolio, including strategic projects.

Q. Please provide a brief outline of your educational background and business experience.

A. I obtained my bachelor's and master's degrees in accounting from the University of South Florida and was licensed as a Certified Public Accountant in the State of Florida in October 2006. After spending several years in public accounting, I began working at Tampa Electric in February 2010 as an internal auditor. Since then, I have held several positions in different functional areas, each of which involved more responsibility and leadership. I have spent the last few years in our customer experience department focused on customer strategy, strategic projects, research, digitalization, and operational support.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to: (1) describe the company's customer experience department and its goals, (2) describe how the company's focus on the customer experience has evolved since the company's last rate case in 2013, (3) explain how the company measures its customer experience performance and how the company's performance has improved in the last eight years, (4) explain the programs the company has implemented to assist low income customers and customers impacted by COVID-19, (5) provide details about the company's plans for continuing to improve its customer experience, including the options available as part of our new Advanced Metering Infrastructure ("AMI") system, (6) demonstrate that the company's customer experience capital budget and planned additions for 2022 are reasonable and prudent, and (7) show that the company's proposed level of operations and maintenance expense ("O&M") for customer experience activities in the 2022 test year is reasonable and prudent.

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

A. Yes. Exhibit No. MLC-1, entitled "Exhibit of Melissa L. Cosby," was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of seven documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Melissa L. Cosby
Document No. 2	Tampa Electric JDP Study Highlights – Residential
Document No. 3	Tampa Electric JDP Study Highlights – Business
Document No. 4	O&M by Functional Area 2013 – 2022
Document No. 5	Capital by Major Project 2013 – 2022
Document No. 6	Contact Center Metrics

Q. Are you sponsoring or co-sponsoring any sections of Tampa Electric's Minimum Filing Requirement ("MFR") schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR schedules listed in Document No. 1 of my exhibit. The data and information contained in these schedules were taken from the business records of the company and are true and correct to the best of my information and belief.

TAMPA ELECTRIC'S CUSTOMER EXPERIENCE AREA

Q. What are Tampa Electric's three major areas of strategic focus?

A. As noted in the direct testimony of Tampa Electric witness Archibald D. Collins, our major areas of strategic focus are safety, cleaner and greener operations, and a World Class customer experience. While we have an entire department dedicated to the customer experience, every Tampa Electric team member is responsible for delivering a World Class customer experience.

Q. How many people are employed by Tampa Electric in the customer experience department and what are the major functional areas in that department?

A. Approximately 450 team members work in the customer experience department. Most of these team members work in the contact center operations serving both Tampa Electric and Peoples Gas customers. The rest are responsible for customer strategy; communications and marketing; digital experience; business customer experience; new construction; customer solutions such as demand side management and programs and services; business solutions; billing and exceptions; account management; and credit and collections.

Q. What are the company's goals in the customer experience area?

A. Our overarching goal is to provide customers with a World Class customer experience.

Q. Has Tampa Electric formalized its plans for achieving this goal?

A. Yes. In 2017, the company developed a formalized and updated Customer Experience Strategy and Customer Commitment Statement. A key element of this strategy is that all team members are responsible for delivering a World Class customer experience.

The company's Customer Experience Strategy focuses on these six drivers of customer satisfaction:

1. Power Quality & Reliability
2. Billing and Payment

3. Price
4. Corporate Citizenship
5. Communication
6. Customer Care – digital, phone, and field

The Customer Experience Strategy states that we will deliver outstanding customer service by:

1. Creating an effortless customer experience;
2. Empowering customers to design their energy experience of choice; and
3. Building strong connections with our customers.

Q. What actions has the company taken to ensure that all employees feel responsible and empowered to deliver a World Class experience to customers?

A. Tampa Electric developed a Customer Commitment Training Program in 2018 to help team members better understand their role in serving customers with excellence. The company successfully deployed the training program in 2019. Over 99 percent of our team members completed one of the 173 classroom sessions we held.

EVOLUTION OF CUSTOMER EXPECTATIONS

Q. Have customer expectations for electric service changed in the last decade?

A. Yes. Customer expectations for electric service continue to grow and evolve. Customers expect more than just safe, reliable, and affordable electric service. This change has been largely driven by technology and advancing customer service standards in other industries. Our customers live in a more digital world and expect an experience from their electric utility that is similar to what they receive from companies like Amazon and Uber. Customers want to self-serve using their "channel" of choice - whether telephone, email, text, or web via mobile or desktop website - whenever and wherever they want. Customers want faster service, which raises service level expectations. They want a consistent and personalized experience that is simple to use, convenient and innovative. Customers want information specifically related to services that impact their account, power quality and reliability, billing and payment, and they want to know what the utility is doing to improve the utility's infrastructure and the environment.

Q. How do customers expect Tampa Electric to contribute to a cleaner, greener environment?

A. Tampa Electric has reviewed industry data and completed its own market research. This research shows that both residential and business customers care about the environment and want the company to leave a cleaner planet for future generations by investing in renewable energy like solar. Tampa Electric witness Jose A. Aponte’s direct testimony explains the company’s planned investments in additional solar.

CHANGES IN CUSTOMER EXPERIENCE SINCE 2013

Q. How has Tampa Electric responded to these changing expectations?

A. Tampa Electric improved the customer experience to meet changing customer expectations by using new technology, new processes, and new training. My direct testimony will explain how these improvements have created the company’s World Class customer experience.

Q. How much capital has the company invested in the customer experience area from 2013 to 2021?

A. The company has invested approximately $132 million in the customer experience area between 2013 and 2021.

New Technology Projects

Q. What technology capital projects has Tampa Electric completed since 2013?

A. The company has invested in seven major technology projects since 2013 to improve the customer experience:

1. SAP Customer Relationship, Management & Billing "CRB" System Implementation & Continued Enhancements
2. Outage Enhancements
3. Contact Center Management ("CCM") and Interactive Voice Response ("IVR") System Enhancements & Replacement
4. Automation Functionality
5. Customer Preference Center
6. Voice of the Customer
7. Web & Portal Enhancements

Unless otherwise noted, the capital investments below do not include AFUDC. Additionally, all amounts included in this document are for Tampa Electric only and do not include amounts for Peoples Gas.

1. SAP Customer Relationship, Management & Billing "CRB" System Implementation & Continued Enhancements

Q. What is the SAP Customer Relationship Management and

Billing System ("CRB") Implementation?

A. The company modernized its legacy mainframe billing system with a state-of-the-art customer management and billing system that is a solution for managing customer accounts, billing, payment, credit, and collection services. The CRB system integrates with over 60 other application systems.

Q. What was the cost for the CRB System Implementation?

A. The company made a capital investment of approximately $83 million in the new CRB system including AFUDC, and approximately $5 million in subsequent enhancements made to the system after it went live in 2017 through 2021. Additionally, enhancements to the CRB system are planned for 2022 in the amount of approximately $7 million. These enhancements are necessary to keep pace with changing technology and continue to meet evolving customer expectations.

Q. How has this change to the company's billing solution improved the customer experience?

A. Tampa Electric's decision to modernize the billing platform was important to reduce the risk of system failure due to obsolescence, as the mainframe solution was outdated and becoming increasingly challenging to support. The new CRB system has significantly increased the company’s capabilities and enhanced the customer experience in several ways. First, Tampa Electric redesigned company bills to include usage graphs and significant customer messages in a more customer-friendly format. Second, the new solution gives customers more billing options. For example, customers with multiple accounts have the option to include all their accounts on one bill. Third, we created a self-service customer portal with paperless billing, account management and outage reporting. Fourth, year over year, Tampa Electric has reduced the number of estimated bills and the number of adjustments to bills and has improved the timeliness of the issuance of bills. Tampa Electric also used the CRB implementation, in combination with various other automation tools, to streamline back-office credit and collection activities. The company has also been able to speed up the processing of customer payments to multiple times per hour. Previously, these payment files were run once a day during nighttime hours, which resulted in payments being processed less efficiently.

2. Outage Enhancements

Q. What is the Outage Enhancements Project?

A. The company enhanced outage communications by improving the outage map, improving the methods for how outages are reported, and improving the communication of outage updates.

Q. What was the cost for this project?

A. The company has invested approximately $2 million in enhancements to the outage communication process, with approximately $1 million planned for 2022.

Q. How has this project improved the customer experience?

A. We know that customers want their power to always be on; however, in the event a customer experiences an outage, customers want Tampa Electric to communicate with them proactively and often, with clear and transparent information about their outage. By improving the outage communication process, we have significantly improved overall customer satisfaction by giving customers the information they need in the event of an outage. These improvements include: (1) enabling two-way texts; (2)

providing at least three data points on all outage related communications; (4) an improved user experience and clarity of information on the outage map with the ability to report an outage directly from the map; and (5) an address search option on the outage map so customers aren't forced to call if they don't have their account number, meter number, or phone number readily available.

3. Contact Center Management ("CCM") and Interactive Voice Response ("IVR") System Enhancements & Replacement

Q. What is the Interactive Voice Response System replacement project?

A. The project will allow us to replace the current Contact Center Management and IVR systems (CCM/IVR) with new technology that will better serve our customers. Presently, the system handles over 4.5 million calls. Approximately 1.8 million of those are routed to a Customer Service Professional ("CSP") in the form of a call; the other 60 percent are resolved via self-service functionality, without the assistance of a live agent. The new state of the art system will:

- Introduce new channels and allow for improved self-service options - providing foundational technology that will allow for development of artificial intelligence

(AI) features such as predictive intent and chat.

- Improve the agent experience with a modern agent desktop that seamlessly integrates with CRB and other business systems, enabling agents to assist customers more efficiently and effectively.
- Improve operational efficiencies by delivering inbound interactions to the best available agent the first time, reduce transfers, and rapidly/automatically adjust to intra-day conditions with modern management tools.

Today, the CCM/IVR platform manages customer interactions for more than 1 million combined customers of Tampa Electric and Peoples Gas System. In addition to the call management, the platform is an important self-service tool for payments, payment arrangements, and outage reporting. The current CCM/IVR platform was purchased in 2012 and implemented in 2014. The current environment does not meet Customer Experience's digital vision of providing an easy, convenient, and innovative experience where customers can conduct business with Tampa Electric and Peoples Gas System whenever and wherever they want. The project is slated to go live in mid-2021.

Q. What was the cost for this project?

A. The company has invested in approximately $4 million in enhancements to the existing IVR since 2013. Beginning in 2020, the company began replacement of the existing IVR system and plans to invest approximately $8 million for the project.

Q. How has this project improved the customer experience?

A. Enhancements to the CCM/IVR system and processes allow for an improved phone experience for customers, as well as improved self-service capability for customers when calling the company. These updated systems will allow for improved self-service offerings, reduced call volume, and natural voice response which will make the system easier to use as well as provide customers with additional contact choices such as chat.

4. Automation Functionality

Q. What is the Automation Functionality project?

A. The company automated certain transactions and processes to increase efficiencies, improve self-service, and provide a more streamlined experience to customers. Specifically, the company streamlined the move in / move out process to improve the overall experience for these high-volume transactions, including automation of the process for customer move ins performed via self-service. The company also developed a simplified workflow to automate repetitious processes. This has increased efficiency and improved accuracy with new account activations by adding intuitive workflows and pop-up messaging that guides the CSP with account activation and beneficial program enrollments for customers.

Q. What was the cost for this project?

A. Between 2013 and 2021, the company has invested approximately $11 million in automation, with an additional investment of approximately $2 million planned for 2022.

Q. How has this project improved the customer experience?

A. The automation of certain processes and transactions has made it easier for customers to do business with us when and where they want. By making it easier for customers to self-serve, we have been able to provide a better customer experience for customers that choose to call us.

5. Customer Preference Center

Q. What is the Customer Preference Center Project?

A. The company designed and implemented a platform to allow customers to set channel and contact preferences for outbound communications for outages, billing & payments, and electric usage and marketing, allowing the customer to be in control of how and when the company contacts them. The platform also enhances our ability to provide outbound communication via multiple communication channels.

Q. What was the cost for this project?

A. The company has invested approximately $2 million in the Customer Preference Center through 2021.

Q. How has this project improved the customer experience?

A. Because this new platform allows for customers to set their own communication preferences, customers will control what information they receive and how they receive it.

6. Voice of the Customer

Q. What is the Voice of the Customer project?

A. In 2020, the company invested in a Voice of the Customer ("VOC") platform to systematically gather our VOC data and feedback in a central location through integration with other key systems. VOC is a concept (or program) that encompasses the collective insights of our customers' needs, wants, perceptions, preferences, and expectations so we better understand our customers. The main benefit of a VOC program is that it can measure the experience of a customer at key points of interaction, in real time, allowing us to draw more meaningful insights to improve the customer experience. Through implementation of the VOC platform, we created our first transactional survey that is automatically sent to customers based on their interaction with us. There are additional investments planned over the next few years to continue to capture valuable customer feedback with the goal of improving customer experience.

Q. What was the cost for this project?

A. In 2020 and 2021, the company invested approximately $1 million in the VOC platform with additional investments in the platform planned for 2022.

Q. How has this project improved the customer experience?

A. This project has created a central platform for customer feedback, creating a more holistic view of our customers and using the data to create actionable insights to address points of customer concern and determine the right initiatives to improve the customer experience.

7. Web & Portal Enhancements

Q. What is the Web & Portal Enhancements project?

A. Tampa Electric launched its first online customer self-service portal ("customer portal") in 2017 as part of the CRB system implementation. Tampa Electric's online customer portal allows residential and commercial customers to complete more than a dozen functions, including viewing their bills, reporting an outage, understanding their electricity usage, reviewing their payment history; making payments at any time; and starting and stopping service.

Since the launch in 2017, Tampa Electric improved usability by enhancing the design and offerings of menus and redesigned transactional screens to make them more accessible for mobile users.

Q. What was the cost for this project?

A. The company has spent approximately $7 million on enhancements to the external website and customer portal during years 2017 - 2021, with additional enhancements planned for 2022.

Q. How has this project improved the customer experience?

A. Tampa Electric adopted a "mobile first" strategy that allows customers to do business with the company on their device and channel of choice, meaning that customers can contact us when and where they want using the method of communication they choose. The mobile-first focus is balanced by ensuring that customers can also interact with customer service professionals and/or non-digital solutions. Customer digitalization, through online service, strongly shapes customer satisfaction and creates efficiencies that improve the telephone experience.

Process Improvements

Q. Has Tampa Electric made any improvements to its customer service processes since 2013?

A. Yes. Tampa Electric made several process improvements, including:

1. Customer Experience Center Process Improvements
2. Business Customer Improvements

3. Other Process Improvements

1. Customer Experience Center Process Improvements

Q. What are the Customer Experience Center Process Changes?

A. Customer Experience Centers are the company's central customer connection hubs that handle all types of incoming channels, including telephone, email, and social media. The Customer Experience Centers handle emergency and non-emergency requests 24 hours a day, seven days a week. Tampa Electric has four physical Customer Experience Centers located in downtown Tampa, Ybor City, Miami, and Plant City.

Tampa Electric has separate teams of CSPs that are specially trained to assist residential customers, business customers, new construction requests, and demand side management programs.

Tampa Electric made several improvements to the Customer Experience Centers over the last several years, including:

- Process and Procedure Improvements: Tampa Electric redesigned more than 300 legacy processes and procedures and trained team members in their use. This reduced unnecessary handoffs and improved quality and accuracy.

For example, Tampa Electric significantly reduced the amount of time a customer spends on the phone with a CSP to initiate new service. Tampa Electric also deployed a secure document upload system so CSPs and customers can securely email documents between each other, eliminating the use of fax machines.

- Greeting Card Campaign: When a CSP recognizes that a customer has achieved a specific milestone (new home purchase, birthday, special event, etc.), or when a customer expresses they may be going through a rough time, the CSP can send the customer a hand-written greeting card. The program has been wildly successful and has received many customer accolades.
- Universal Agent Cross Training: Tampa Electric implemented a more comprehensive training methodology and approach to ensure all CSPs are knowledgeable and able to assist customers on the first attempt.
- Quality Monitoring: Tampa Electric implemented a quality monitoring program to support and improve the customer experience through audio/visual monitoring of inbound and outbound phone and online customer interactions. The evaluation process measures quality standards; first call resolution; transactional accuracy; compliance with applicable Tampa Electric policies, rules, laws, and regulations; and customer impact of actions. In

addition, the company included customer service orientation behaviors supporting a positive customer experience and alignment with the drivers of customer satisfaction as defined by J.D. Power ("JDP").

2. Business Customer Improvements

Q. What Business Customer Process Improvements has Tampa Electric made since 2013?

A. Tampa Electric has enhanced the experience for our business customers through several new changes:

1. The company made it easier for business customers to execute large transactions for multiple accounts on the customer portal (e.g. download bills in bulk, make a single payment to multiple accounts, search for payments made for multiple accounts).
2. The company enhanced the SAP user interface to pull critical information more quickly and better assist large customers when they call.
3. In late 2017, the company started a mid-market account management team focused on proactively serving mid-sized commercial customer accounts with billing and reliability issues. The team identifies recurring issues to ensure issues are addressed and resolved as quickly as possible.

4. Tampa Electric created an internal, cross-functional team ("Reliability Council") in 2019 to address key reliability issues (e.g. proactive switchgear replacement). These efforts are discussed in greater detail in the direct testimony of Tampa Electric witness Regan B. Haines.
5. The company conducts a bi-annual key account management survey to gather customer feedback with the goal of identifying opportunities for improvement.
6. The company implemented and began tracking key metrics (e.g. number of key account site visits) to ensure we are serving business customers appropriately.
7. The company enhanced the outage management process for business customers by:
   a. Implementing an internal communications process to ensure information is shared internally, so account management can proactively keep business customers informed during outages.
   b. Instituting a more coordinated and structured process for planned outages.
   c. Enhancing the outage map, making it more informative and easier to use and improved outbound communications for outages.

3. Other Process Improvements

Q. What other process improvements has Tampa Electric recently implemented to improve the customer experience?

A. In addition to the comprehensive changes noted in the categories above, Tampa Electric has implemented several additional improvements directly focused on improving the customer experience:

1. By establishing usability testing and implementing best practices in web design, Tampa Electric improved the functionality of its website. The newly implemented Integrated Marketing & Communications Program ensures we are providing an enhanced experience through our social media platform and traditional communications.
2. Tampa Electric provides a welcome letter when customers initiate service. This correspondence informs the customer of important information around their service and billing and payment options. This letter is delivered either as a hard copy by U.S. mail or electronically through email depending on the customer's selection at the time of sign-up.
3. Tampa Electric has refreshed key messaging on its social media, website, and bills to ensure we present relevant communication related to safety, reliability, conservation programs, billing and payment services, and

the company's online portal.

New Training

Q. Has Tampa Electric implemented any new or additional training in the customer experience area since 2013?

A. Tampa Electric has significantly enhanced the training programs for the company's CSPs and other customer experience business units, such as billing and payment, and credit and collections, to promote accuracy, consistency, and a World Class customer experience. These training programs include the programs below, in addition to several others:

1. Universal Agent Training: All CSPs undergo the universal agent training program, expanding their ability to resolve customer issues, greatly reducing call transfers and hold times. This supports our goal of getting it right the first time and minimizing hand-offs – both of which contribute to fewer calls to the call center and a happier customer.
2. Soft Skills Training: The soft skills training program and accompanying quality program was initiated to ensure a consistent and comprehensive call flow, focused on soft skills and positive customer interaction.
3. Monthly Refresher Training: All customer experience team

members are provided with customized monthly refresher training sessions highlighting procedural changes, system enhancements and process improvements.

4. New Hire Training: Formal new hire courses have been developed and implemented for each area in the customer experience department, providing standardized content and a consistent learning experience. This approach promotes uniform customer interactions and improves employee retention. The new hire content also serves as the foundation for our cross-training programs, designed to support internal promotional opportunities and enhanced agility for our smaller business units.

As part of its commitment to quality customer service, Tampa Electric contacts all customers who file a formal or informal Commission complaint and works these matters to resolution with the customer.

Tampa Electric also monitors phone interactions and provides ongoing monthly feedback to agents on interactions with areas of opportunities and positive reinforcement.

Tampa Electric also has a process whereby other departments involved in a customer's journey can provide feedback directly to frontline team members regarding how the customer's request was handled and provide insight into areas of opportunity for future similar interactions.

MEASURING THE CUSTOMER EXPERIENCE

Q. How does the company measure its performance in the customer experience area?

A. The company measures its performance in the customer experience area based on customer satisfaction scores as measured by JDP, several internal performance metrics, and by tracking FPSC complaints.

Q. In general, how has the company's performance in customer experience trended since 2013?

A. Tampa Electric's overall customer satisfaction, as measured by JDP, steadily increased from 2013 to present. In the residential category, Tampa Electric is ranked in the second quartile in 2020 for overall customer satisfaction. The company is also ranked in the first quartile for three out of six drivers of satisfaction including Price, Billing & Payment, and Customer Care. The company ranks in the second quartile for the remaining three drivers - Corporate Citizenship, Power Quality and Reliability, and Communications. In the business category, Tampa Electric is ranked in the first quartile and second in our segment for overall customer satisfaction and ranked in the first quartile for all drivers of satisfaction. Tampa Electric also steadily improved its industry rank year over year in both the residential and business studies. The company is ranked 40th out of 143 residential brands, and 4th out of 86 business brands as of the end of 2020.

As shown in Document No. 2 and 3 of my Exhibit, Tampa Electric has shown improvement in overall customer satisfaction from 2013 - 2020.

Q. Earlier you described the customer experience projects that Tampa Electric has completed since 2013. Have these projects resulted in measurable improvements to the customer experience?

A. Yes. Tampa Electric's performance in internal metrics has improved because of the company's investments in technology, new processes, and new training since 2013. The company has improved in several billing and payment metrics, including:

- Greater than 98 percent of all bills were generated within one day of the scheduled billing cycle,

- 99.99 percent of customer payments were processed within 3 days of receipt,
- Less than 0.30 percent of Tampa Electric's bills were estimated,
- 46 percent of Tampa Electric's customers were enrolled in paperless billing,
- 79 percent of payments were electronically transmitted and processed.

The company also improved in several telephone service metrics, including:

- Tampa Electric's telephone customer service ratings for residential customers have improved by 181 points, from 669 in 2013 to 850 in 2020. For business customers, telephone customer service ratings have improved by 182 points, from 667 in 2013 to 849 in 2020.
- In 2020, 72 percent of JDP residential survey respondents and 76 percent of business respondents who called Tampa Electric were able to resolve their issue with the first phone call.
- As I explain in greater detail below, the company has also achieved significant improvement in average speed of answer, call abandonment rate, telephone service level, and call volume.

Finally, the company also improved in several digitalization metrics:

- 67 percent of Tampa Electric's active customers have an online portal account.
- In 2020, Tampa Electric responded to over 90 percent of emails in 24 hours or less and over 99 percent in 48 hours or less, including weekends and holidays.
- Tampa Electric's online customer service ratings have improved by 111 points for residential customers, from 732 in 2013 to 843 in 2020. For business customers, ratings have improved by 127 points, from 740 in 2013 to 867 in 2020.
- In 2020, 88 percent of customers were able to self-service through digital means.
- In 2020, approximately 61 percent of calls were handled via self-service through the IVR.
- In 2020, 77 percent of JDP residential survey respondents who used online/web resources to contact Tampa Electric resolved their issue with the first contact. This represents an increase of 21 percentage points since 2017 and the highest score for this metric to date. Similarly, 75 percent of business respondents who contacted Tampa Electric via online/web were able to resolve their problem with the first contact. This represents the second highest score for this metric and an improvement of 13 percentage points since 2015.

Q. What are the major internal performance metrics used by the company to measure its performance in the customer experience area?

A. The main performance metrics the company uses to measure performance are:

1. Telephone service level
2. Email service level
3. Average speed of answer
4. Average handle time
5. Call volume and abandonment rate

As shown in Document No. 6 of my Exhibit, Tampa Electric has shown improvement on each of these metrics since 2013. Due to the improvements Tampa Electric has made since 2013 in the form of people (*i.e.* training), process, and technology, our customers have experienced more efficient, consistent, and accurate interactions with fewer unnecessary hand-offs, resulting in an overall better customer experience as supported by these improved metrics.

Q. Has the company won any awards in the customer experience area since 2013?

A. Tampa Electric was awarded the "Trusted Business Partner" designation in 2019 and 2020 by Cogent/Escalent.

Q. How has the company performed in FPSC customer complaints since 2013?

A. Customer complaints decreased by nearly 57 percent, from 561 total complaints in 2013 to 243 complaints in 2020. This represents the lowest number of complaints since 2012. Commission infractions also decreased, with only two since 2016. The decrease in complaints is driven largely by implementation of the new billing system in 2017 and by Tampa Electric’s strong customer focus and improved business operations. Tampa Electric uses these complaints as an opportunity for continuous improvement, either through team member training, process or system changes, and/or improved customer education.

Q. Please summarize how the company’s performance in customer experience has improved since the company’s last rate case in 2013?

A. Tampa Electric has made substantial improvements to the customer experience, as evidenced by the company’s strong performance in the areas of customer satisfaction as measured by JDP, key internal metrics, and tracking of FPSC complaints. In all cases, Tampa Electric has improved in performance as compared to 2013 due to the focus on a customer-centric culture with a strategic plan and vision for improving the experience.

PROGRAMS FOR LOW-INCOME CUSTOMERS AND COVID-19 ASSISTANCE

Q. Has the company implemented programs to assist low-income customers?

A. Yes. The company has a long-standing practice of offering short-term payment arrangements and began offering long-term installment plans to provide flexibility with extensions when customers are struggling to pay their Tampa Electric bill. If assistance beyond a payment arrangement is needed, Tampa Electric works with a network of local, regional and federal non-profits, including community action agencies, to aid with utility bills and other services provided by these entities. Examples include referrals to United Way's 2-1-1, Low-Income Home Energy Assistance Program (LIHEAP) and Emergency Home Energy Assistance for the Elderly Program ("EHEAP") funding, and Tampa Electric's SHARE Program, which is administered through the Salvation Army.

Tampa Electric enhanced the online agency portal for regional non-profit partners, which allows Tampa Electric’s social service agencies to self-serve and work more efficiently in assisting customers in need. As a result, Tampa Electric has increased its social service agency partnerships from 20 partners in 2013 to 120 partners in 2020 and has collaborated with these agencies to provide over $10 million in assistance dollars to over 35,000 households in 2020.

Tampa Electric also works with customers to advise them on practices to improve energy efficiency. It offers 35 programs and rebates for residential and commercial customers; provides education on energy saving tips through customer communication; and conducts on-site high bill investigations, walk-through energy audits, and online energy audits.

Also, the company’s Neighborhood Weatherization program helps qualified customers manage their electricity costs by making their home more energy efficient. If their home qualifies, we will provide and install an energy-saving kit at no cost for these customers. The customer also receives a comprehensive home energy audit as part of this program.

Q. Did the company take action to help customers impacted by the COVID-19 pandemic?

A. Yes. Tampa Electric has taken several steps to assist customers impacted by the COVID-19 pandemic, including:

- Voluntarily suspending disconnections for nonpayment between March and September 2020.
- Created a COVID hardship website that clearly presents available resources through local, state, and federal assistance programs for both residential and business customers.
- Along with our sister company Peoples Gas System, donated an initial $500,000 to the SHARE Program, a partnership between Tampa Electric, Peoples Gas System, and the Salvation Army which supports customers who struggle with paying utility bills. Our employees and other generous customers contributed additional support to approximately 5,000 customers.
- Along with our sister company Peoples Gas System, donated an additional $500,000 to other charitable partner organizations working on the front lines of the pandemic to provide critical support to our communities, including $200,000 to the United Way's efforts for those who lost income, $25,000 to the Florida Virtual School, and $275,000 to other charitable organizations that

provide meals and housing.

- Along with our sister company TECO Peoples Gas, donated an additional $1 million at the end of 2020, distributed across all customers who received LIHEAP or EHEAP assistance in 2020. This resulted in an $85 credit applied on these eligible customers’ accounts.
- Created internal processes for receipt and processing of SHARE applications on behalf of the Salvation Army while that agency developed new processes that did not require face-to-face interaction.
- Developed and implemented modified payment arrangement guidelines to provide greater flexibility for customers.
- Applied for, and received, Commission approval for a fuel cost adjustment that resulted in a temporary bill reduction of approximately 20 percent, during each month from June through August, for a total average bill credit of $78.82 for 1,000 kilowatt-hours. In total, Tampa Electric passed $130 million of fuel cost reductions along to customers.
- Launched outreach efforts encouraging our team members, customers, and local businesses to consider donating to the SHARE program. Organizations such as the Tampa Bay Lighting responded by assisting nearly 100 customers with a $150 credit applied directly to their bills.
- While disconnections for non-payment were suspended,

Tampa Electric launched regular communications to customers regarding payment arrangement options and details on how to obtain customer assistance and resources while encouraging customers to contact us, to learn more about our flexible payment arrangements and installment plan options available to them.

- Developed and implemented modified reconnection guidelines to ensure that customers that are unable to make full payment would still have an opportunity to be reconnected by making a partial payment and committing to a longer-term payment extension as needed.
- When disconnections resumed, customer service professionals also followed up with personal phone calls to those customers who had not reconnected service after 3 days, with the intent of providing assistance options for reconnection.

FUTURE PLANS FOR IMPROVEMENT

Q. Does the company's strategy reflect the changing nature of customer expectations?

A. Yes. Customer expectations are evolving primarily because of their digital experiences with other industries, such as Amazon or Uber. Customers count on us for more than just safe, reliable, and affordable electricity; they want easy, convenient, and innovative services and expect to get the most value for their dollar.

Tampa Electric is relentlessly focused on exceeding customer expectations. Tampa Electric plans to leverage digital technologies to improve the way we work and to position the company and our customers well for the future. The company plans to deliver programs and services that expand options for customers across the spectrum of energy needs.

Q. Does Tampa Electric have additional customer service initiatives that it plans on implementing in the near future?

A. Yes. Below are several customer initiatives planned for the near future:

a. Customer Commitment Training: Tampa Electric will expand the customer commitment training program that began in 2018 to include external contractors that directly serve customers. The company will also implement an annual refresher course for existing team members.

b. Speech Analytics: Tampa Electric will use speech analytics to improve quality of service. Speech analytics transcribes calls to create searchable text with audio playback capability. This will allow the company to identify points of customer concern and reveal the cause/effect relationships that underlie performance and business outcomes across the company. The additional step of creating a "category" provides the ability to trend and analyze the speech analytic results by call type or reason for calling.

c. Customer Champion Network: Efforts are underway to kick off a Customer Champion Network as part of our greater Customer Experience Strategy. This team member-led network would work to ensure customer feedback is evaluated, considered, and utilized to determine short and long-term customer needs, identify points of customer concern, and identify opportunities for improvement. The network members would also serve as brand ambassadors that share the many good things the company is doing to serve customers and the community. The company plans to launch the program internally in 2021 and then roll it out to customers after the group is fully activated and engaged.

d. Accuracy Program: The objective of the Accuracy Program will be to identify areas of opportunity where team members are performing tasks that directly impact a customer to ensure they are done correctly and in a timely manner. The intent of this program is to track these activities across all customer communication channels and identify opportunities for improvement. The program will also identify key processes where team members can work to mitigate errors and/or mistakes.

e. Consistent Outbound Communication Process: The purpose of this initiative is to create a methodology that ensures consistency and documentation for all outbound customer requests. Centralizing requests will allow Tampa Electric to: (1) utilize a consistent methodology of completing requests for outbound communications; (2) ensure the message was appropriately vetted, approved, and aligned with other requests; (3) internally communicate the message being sent (especially to our frontline); (4) ensure consistent messaging across all communication channels; (5) ensure the communications covered all key components and reached our customers in a timely manner; and (6) ensure our customers are not overwhelmed with multiple communications within a timeframe.

Q. How will implementation of the AMI system described by

Tampa Electric witness Regan B. Haines enable the company to continue improving the customer experience?

A. As explained in greater detail in the direct testimony of Mr. Haines, Tampa Electric is currently installing state-of-the-art, smart electric meters for nearly every customer.

When the project is complete in December of 2021, it will serve as a foundation for many future improvements, including:

1. The AMI meters will automatically inform Tampa Electric when an outage occurs, enabling the company to diagnose and repair the problem more quickly. Additionally, the technology will provide customers with more timely, customized information on the outage cause and status of restoration.
2. The process to start or stop service will be more convenient, as these will occur remotely and not require a field visit.
3. Customers will have the ability to manage their energy use throughout the month, set up alerts when consumption and bills are approaching certain levels, and monitor daily usage through mobile devices.

4. Customers will have the ability to pick their own bill due date.
5. Electricity usage information will be relayed automatically to Tampa Electric for billing purposes, limiting on-site or drive-by visits to read meters or to cut or restore power.

Q. Does the company offer energy-efficiency programs or services?

A. In support of the Florida Energy Efficiency and Conservation Act (FEECA) Tampa Electric has been encouraging conservation and energy efficiency for nearly 40 years. In that time, the company has performed more than 575,000 energy audits that help customers use energy more wisely and become more energy efficient. At the end of 2019, more than 1.1 million customers have participated in energy-efficiency programs. Tampa Electric offers 35 DSM programs to help residential and business customers reduce their overall energy usage, and ultimately their energy costs. Tampa Electric proudly offers more DSM programs than any other electric utility in Florida. More detail regarding the company's energy efficiency programs can be found in the company's DSM Plan, which was filed February 19, 2020 in FPSC Docket No. 2020053-EG and approved by the

Commission by Orders issued August 3, 2020 and August 28, 2020 in the same docket.

Q. Is the company proposing tariff changes in this proceeding to better meet the needs of customers and improve the customer experience?

A. Yes. Below are several tariff changes that will benefit customers:

1. **Lower service charges due to the AMI conversion project.** The company has replaced most of its meters with AMI since the last time the Commission set the company's service charges. This technology allows remote reading and operation of the meters installed at the customer premises and significantly reduces the need to roll trucks into the field to effect certain actions, including activation and deactivation of meters for existing customers. This reduced cost has been reflected in the cost support for service charges, allowing a significant reduction in the proposed charges themselves as well as the revenues collected from them. This is just one of the many customer benefits that will result from this conversion.
2. **Creation of a new set of GSLD rates to serve customers previously served under the IS rates and the largest**

sized, higher voltage served customers from the GSD set of rate classes. The IS rate schedules are closed to new business, but existing customers served under those rate schedules will be moved to the new GSLD rate schedules. If these large customers moved to the new GSLD rate are participating in the company's Industrial Load Management DSM program (GSLM 2&3), their participation will be maintained in the DSM program with the same monthly credits paid as they are paid currently for their providing the ability to interrupt their service.

3. **Changes to the charges associated with Lighting Service Rate Schedule LS-1.** As the Commission is aware, Tampa Electric is converting all its outdoor lighting equipment utilizing High Pressure Sodium and Metal Halide fixtures to new highly efficient Light Emitting Diode (LED) outdoor lighting facilities. There are many customer benefits associated with LED lights including longevity, durability, energy-efficiency, and safer, better quality of light.

Please refer to the direct testimony of Tampa Electric witness William R. Ashburn for more details on service charges and tariff changes.

2022 CUSTOMER EXPERIENCE PROPOSED RATE BASE ADDITIONS

Q. What is Tampa Electric's capital budget for the Customer Experience area in 2022?

A. As shown in Document No. **5** of my exhibit, the capital budget for the Customer Experience area totals approximately $23 million for 2022. The projects reflected in this budget are shown on Document No. **5** of my composite exhibit.

Q. How does Tampa Electric determine capital budget for the customer experience area?

A. The Customer Experience department identifies capital improvement opportunities based on analysis of industry best practices, identification of points of customer concern through customer journey mapping, identification of gaps in customer satisfaction, analysis of customer feedback through our Voice of the Customer program, analysis of input from team members across the organization, as well as system issues identified in the meter to cash process. These needs are reviewed and prioritized to develop the Customer Experience technology roadmap.

Q. How does the company plan and manage its major capital improvement projects in the customer experience area?

A. The Customer Experience team drafts a business case for each capital project that identifies potential benefits to the organization and to the customer and supports the capital project's priority ranking and cost. These capital projects are then submitted through the company's capital approval process. Once approved, the capital projects are tracked through Customer Experience's capital project portfolio and are reviewed monthly to ensure quality, timeline, and budget are on track for the projects.

Q. You previously explained the company's rate base additions in the customer experience area from 2013 to 2021 and why they were prudent and that they continue to be used and useful to serve the company's customers. Now please describe and explain the additions to rate base in the customer experience area forecasted to occur in the 2022 test year. Why are each of these major projects prudent and how will they benefit the company and its customers?

A. The major projects included in capital for the 2022 test year are:

1. Update technology for the external website to replace

the existing, dated technology, as well as continued enhancements to web and portal functionality and usability. This will make it easier for customers to self-serve online.

2. Enhanced outage information on the portal outage map and enhanced outage communications that will provide customers with more detail and more frequent status updates.
3. Continued automation of key transactions and implementation of process efficiencies. These enhancements will help to eliminate points of customer concern and unnecessary or inefficient costs, thereby improving customer satisfaction and allowing for investments in other customer improvements.
4. Continued enhancements to the CRB system and processes, streamlining the process between meter readings and customer payment. These enhancements will help to further eliminate points of customer concern in the customer's journey and simplify customers' interactions with the company.
5. Enhancements to the IVR system and processes to continuously improve upon the phone experience for customers, as well as improve self-service capability for customers.
6. Implementation of a Prepaid Billing program that will

allow customers with AMI meters to pay as they go (any amount, any time) and "load their meter" with credits. Customers will also be able to monitor interval usage, account balance, and add money as needed to their account.

7. Development of other digital offerings including:
   a. Replacement of outdated technology used for the external website (www.tampaelectric.com), making it easier to manage content, to support improved website navigation, and to improve the overall experience for customers.
   b. Continued enhancements to our Voice of the Customer platform to provide a more personalized experience for customers.
   c. Development of an omni-channel platform to capture customer interaction data regardless of communication channel used to provide a more holistic picture of the customer and further engage the customer in programs and services that may benefit them.
   d. Implementation of virtual assistant chat functionality to provide a real-time response to customer inquiries after hours and on weekends when personal interaction is not available.
   e. Use of predictive data analytics and AI-assisted

data technologies to identify patterns and predict future customer behaviors or actions and provide a more personalized experience.

2022 CUSTOMER EXPERIENCE O&M EXPENSES

Q. What are Tampa Electric's customer experience O&M expenses budgeted for 2022 and how has the amount varied since 2013?

A. Document No. 4 of my exhibit shows the Tampa Electric customer experience budget from 2013 to 2022 by primary account. The total budgeted amount in 2022 is approximately $34 million. This amount is reasonable.

Q. How do these spending levels compare with what would be expected using the Consumer Price Index for Urban Consumers ("CPI-U") escalation factors using 2013 as a benchmark?

A. Document No. 4 of my exhibit shows that the actual expenses have generally been above what would be expected using the CPI-U as a cost escalator. This is the measure used by the Commission to benchmark O&M expenses for Customer Experience. Budgeted expenses in the 2022 test year are over $3.6 million more than the 2013 O&M benchmark with escalation.

Q. How does the adjusted 2022 test year customer costs per company books compare with the Commission benchmark?

A. As described in the direct testimony of Tampa Electric witness Jeffrey S. Chronister, the company's adjusted 2022 total customer costs are expected to be over the benchmark by $6.4 million. This is related to the company's significant efforts to improve the customer experience described in my direct testimony, and the resulting improvement in customer satisfaction. Specifically, the adjusted test year total customer costs per company books in 2022 is $39.7 million. The adjusted test year total customer benchmark in 2022 is $33.3 million. The customer benchmark calculation is shown in MFR Schedule C-41.

Q. How have customer experience expenses varied over the last five years?

A. As shown in the MFR Schedules C-06 and C-09, the customer experience expenses have increased slightly over the last five years largely driven by our continued journey to improve the customer experience. The company is increasingly focused on meeting and exceeding evolving customer expectations. The company continues to invest in customer services and solutions (e.g., VOC platform, a mobile-first strategy, Customer Preference Center, and IVR/CCM system) that provide a more personalized, transparent, and enhanced customer experience that allows the customer to interact with the company when and where they want through their channel of choice.

Q. What are the main drivers for the company’s customer experience-related O&M expenses?

A. The main drivers of the company’s customer experience-related O&M expenses include labor, outside services (e.g., augmented staffing), and other operational expenses, including but not limited to fees associated with customer billing such as vendor fees and postage, fees associated with customer payments, fees associated with high-volume call answering (“HVCA”), as well as other expenses associated with maintenance of our systems.

Q. What are the major factors that have contributed to an increase in total O&M spending needed in Tampa Electric’s customer experience area?

A. The company’s continuous improvement efforts have been significant, but the total cost for O&M activities has increased. Beginning in 2016, the company increased staffing (internal as well as outside contractors) as the company prepared for the implementation of the new CRB system. In 2017, once the new billing system went live, the company began reducing the use of outside contractors as the system stabilized. As the company continued to gain efficiencies in many areas using the new billing system, the streamlining of processes, and the automation of processes and transactions, the company continued to decrease labor and outside services costs from the 2016 levels. The company also implemented many efficiencies over the years to manage O&M, including:

1. Improved various customer service levels – phone, e-mail, and streetlights
2. Reduced call volume to below 2014 levels
3. Reduced hold time and average handle time
4. Significantly improved self-service utilization
5. Improved First Contact Resolution from below to above industry averages
6. Improved timely and accurate billing and reduced estimated bills
7. Increased electronic billing and payment participation levels
8. Streamlined, documented, automated and trained team members on hundreds of processes

These efficiencies allowed the company to invest in more strategic functions including customer research, customer strategy and training, enhanced customer communications, and digital customer solutions. These strategic investments allowed for an improved customer experience and resulted in a substantial increase in overall customer satisfaction as measured by JDP.

Q. What safety initiatives are reflected in customer experience O&M expenses for the 2022 test year and why are those initiatives beneficial for customers?

A. The Customer Experience department budgets approximately $100,000 per year on safety initiatives including Vimocity, a safety platform that brings sports medicine to the workplace with a focus on injury prevention, ergonomic furniture and equipment (e.g. sit/stand desks), and proper personal protective equipment ("PPE") for new construction, account management, energy auditors, and revenue protection personnel.

Q. How have uncollectible account expenses varied in 2020 and 2021 and is the company's proposed level of uncollectable expenses reasonable for the 2022 test year?

A. Although uncollectible expense increased in 2020 due to the pandemic, we do anticipate that by 2022 our uncollectible activities will return to pre-pandemic levels, as noted in MFR Schedule C-08.

Q. Is the proposed level of advertising expense for 2022 reasonable?

A. Yes, the proposed level of advertising expense for 2022 is reasonable. Advertising expense for customer education is shown in MFR Schedule C-14. The company is increasingly focused on meeting and exceeding evolving customer expectations, which includes educating our customers on services and solutions that will meet their needs. We continue to invest in customer services and solutions that allow the customer to interact with us when and where they want through the channel of their choice but receive updates and communications through various methods of delivery (i.e. printed communications, social media, online platforms).

Q. What steps has Tampa Electric taken to control customer experience O&M costs while maintaining a safe and productive workplace?

A. At Tampa Electric, the safety of our customers and our team members is the company's number one priority. The Customer Experience department is committed to controlling O&M costs while providing a safe and productive work environment for all team members. For example, Tampa Electric shifted the entire customer experience department to work from home, including the Customer Experience Centers, to ensure the safety of our team members during the 2020 COVID-19 pandemic.

Q. Is the overall level of customer experience O&M expense for 2022 reasonable?

A. Yes. The overall level of customer experience O&M expense for 2022 is reasonable. The company remains focused on gaining operational efficiencies to invest in more strategic functions that will enhance the customer experience while keeping overall expenses relatively flat as compared to 2020 and 2021.

SUMMARY

Q. Please summarize your direct testimony.

A. Tampa Electric has a long history of delivering safe, reliable, and affordable electric service to customers while delivering a high value customer experience, as measured by customer satisfaction and evidenced by improved scores since 2013. While this has been the company's legacy, customer expectations, largely driven by technology and information, continue to grow at a rapid pace. It is critical for Tampa Electric and the utility industry to evolve with growing technology and customer expectations. Since Tampa Electric's last rate case, the company has successfully implemented a new customer billing system, a new online portal with a mobile-first approach, improved and increased electronic payment channels, improved customer service levels for our Customer Experience Contact Centers, enhanced billing and payment services, and made hundreds of smaller process and system enhancements to better serve Tampa Electric's customers.

Tampa Electric's enhanced customer experience strategy and customer commitment to engage all team members in this work, has been a foundational component of our corporate culture and continued success. Tampa Electric's commitment is to have a customer-centric culture.

It is this focus and commitment that has resulted in the significant improvements in customer satisfaction year after year. Since 2013, Tampa Electric has improved its residential JDP customer satisfaction ratings by 138 points, and by 187 points in the business study since 2013. These increases have moved Tampa Electric to be ranked in the second quartile in customer satisfaction for residential customers and in the first quartile for business customers, proving that customers are pleased with the people, process, and technology enhancements made by Tampa Electric.

Tampa Electric proposes reasonable capital and O&M budgets for customer experience for the 2022 test year that will allow the company to continue to improve the customer experience.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI
IN RE: PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT
OF
REGAN B. HAINES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

REGAN B. HAINES

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

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

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

A. My duties and responsibilities include the oversight of capital planning and budgeting for the Electric Delivery and Energy Supply departments. This involves coordinating the capital planning process, including the annual and multi-year budgets, and prioritizing and managing capital spending for both departments. I am also responsible for developing Electric Delivery's long-term Transmission and Distribution ("T&D") System plan.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Electrical Engineering and Master of Science degree in Electrical Engineering specializing in Power Systems Engineering from Clemson University in June 1989 and December 1990, respectively. I have been employed at Tampa Electric since 1998. My career has included various positions in the areas of T&D Engineering and Operations.

Q. Have you previously filed testimony before the Florida Public Service Commission ("Commission") or other regulatory authority?

A. Yes. I have filed testimony in Docket No. 20200067-EI, which concerned approval of the company's 2020-2029 Storm Protection Plan ("SPP"). I also testified in the company's 2008 rate case, Docket No. 20080317-EI.

Q. What are the purposes of your direct testimony in this proceeding?

A. The purposes of my direct testimony are to: (1) describe the changes to the company's T&D system since our last rate case in 2013; (2) provide details about the company's future plans for its T&D system and our grid modernization strategy; (3) explain our Advanced Metering Infrastructure ("AMI") project and our progress implementing it; (4) preview other planned grid improvements; (5) demonstrate that the company's T&D plant (*i.e.*, electric delivery) construction program and capital budget for 2022 is reasonable and prudent; and (6) show that the company's proposed level of operations and maintenance expense ("O&M") for Electric Delivery in the 2022 test year is reasonable and prudent. The T&D related capital and O&M spending discussed in my direct testimony does not include any capital or O&M associated with the SPP.

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

A. Yes. Exhibit No. RBH-1, entitled "Exhibit of Regan B. Haines" was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. The exhibit consists of eight documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored By

	Regan B. Haines
Document No. 2	Historical Reliability Indices 2013-2020
Document No. 3	AMI Infrastructure
Document No. 4	AMI Project Costs
Document No. 5	2021 Projected & 2022 Proposed Capital Investments
Document No. 6	Electric Delivery Historical and Projected O&M Expenses
Document No. 7	Electric Delivery 2012 O&M Benchmark Comparison
Document No. 8	Electric Delivery O&M Budget for 2022

Q. Are you sponsoring any sections of Tampa Electric's Minimum Filing Requirement ("MFR") Schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR schedules listed in Document No. 1 of my exhibit. The data and information on these schedules were taken from the business records of the company and are true and correct to the best of my information and belief.

Q. Do the rate base and O&M amounts for the 2022 test year and otherwise discussed in your direct testimony include amounts related to the company's SPP?

A. The amounts I discuss for Electric Delivery capital projects from 2013 to 2020 include historical costs associated with SPP type investments; however, capital costs for 2021 and 2022 exclude SPP projects as these projects will be recovered through the SPP cost recovery clause. Additionally, I have excluded vegetation management and certain inspection costs from 2012 O&M expenses so that the Commission can evaluate our 2022 O&M expense levels under the O&M benchmark test on a comparable basis.

Q. Please briefly describe the company's SPP program.

A. Section 366.96(3), Florida Statutes, requires each public utility to file a T&D SPP that covers the immediate 10-year planning period, and to explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. Tampa Electric submitted its first SPP to the Commission in April 2020 and it was approved later that year in Docket No. 20200067-EI.

TRANSMISSION AND DISTRIBUTION SYSTEM OVERVIEW AND EVOLUTION

Q. Please describe the company's current T&D system.

A. Tampa Electric's service territory covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and parts of Polk, Pasco, and Pinellas Counties. The company has divided its service territory into seven "service areas" for operational and administrative purposes.

Tampa Electric's transmission system consists of nearly 1,350 circuit miles of overhead facilities, including approximately 25,400 transmission poles and structures. The company's transmission system also includes approximately nine circuit miles of underground facilities.

The company's distribution system consists of approximately 6,300 circuit miles of overhead facilities and approximately 414,000 poles. The distribution system also includes approximately 5,500 circuit miles of underground facilities.

The company currently has 216 substations.

Q. What role does safety play in Electric Delivery?

A. Safety is the top priority at Tampa Electric and is integral to the work that we perform. Electric Delivery is committed to the belief that all injuries are preventable and has implemented a Safety Management System ("SMS"). The system is designed to ensure compliance with Occupational Safety and Health Administration ("OSHA") regulations and is aligned with OSHA recommended practices. The SMS consists of 10 elements and includes the following: Safety Leadership; Risk Management; Programs, Procedures, and Practices; Communication, Training and Awareness; Culture and Behavior; Contractor Safety; Asset Integrity; Measuring and Reporting; Incident Management and Investigation; and Auditing and Compliance.

We have reduced the number of work-related injuries reported annually within Electric Delivery by 53 percent since 2013.

Q. What is Asset Management and how has the company integrated Asset Management techniques into its planning and operations for Electric Delivery?

A. Asset Management is a disciplined way of thinking and managing that aligns engineering, operations, maintenance, other technical and financial decisions, and processes for the purpose of optimizing the value of our assets throughout their lifecycles.

Tampa Electric seeks to achieve its asset optimization goals by focusing on three Asset Management objectives.

The first objective is the integration of asset monitoring; health and risk assessment; work planning and scheduling; capital planning; outage planning; risk management; and other supporting asset management processes into continuous business processes.

The second objective is the broader engagement of team members and subject matter experts in these continuous processes, the establishment of asset management responsibilities throughout the organization, and ensuring team members are empowered with industry best practices through awareness and training.

Finally, we sustain the integrated processes and engagement of our teams through documentation and standardization of technical and business processes and the implementation of supporting operational and information technology systems. Applying Asset Management principles gives us a comprehensive understanding of the condition of our assets and the risks associated with them and allows us to better identify and prioritize the work that needs to be done. This level of understanding enables us to improve our planning and scheduling of work, lowers the costs and risks of operating our system, and improves efficiency and reliability – all of which promote a good customer experience. Asset Management is described in more detail in the direct testimony of Tampa Electric witness David A. Pickles.

Q. How has the company's Electric Delivery system evolved since the company's last rate case in 2013?

A. Since 2013, Tampa Electric's Electric Delivery system has evolved in several ways. We expanded our overhead transmission system by approximately 40 miles. We reduced our overhead distribution system by approximately 50 miles and increased our underground distribution system by approximately 890 miles. We placed eight new substations in service and added over 900 single and three phase reclosing devices on the distribution system. We made these changes to ensure that our Electric Delivery system can provide safe and reliable electric service to both existing and new customers.

Q. Please describe the indicators the company uses to monitor reliability and how they relate to what customers experience.

A. The experience our customers receive from Tampa Electric is affected by many factors including the power quality and reliability of our electric T&D system. We measure system performance and track a variety of indices that reflect how our Electric Delivery system performs.

The company calculates and monitors several reliability indices but focuses primarily on System Average Interruption Duration Index ("SAIDI") and Momentary Average Interruption Event Frequency Index ("MAIFIe").

SAIDI indicates the total minutes of interruption time the average customer experiences in a year. It is the most relevant and best overall reliability indicator because it encompasses two other standard performance metrics for overall reliability: The SAIFI and the Customer Average Interruption Duration Index ("CAIDI").

MAIFIe reflects the overall impact of momentary outages on customers and is defined as the average number of times a customer experiences a momentary interruption event each year.

Tampa Electric annually sets reliability goals for both SAIDI and MAIFIe.

We report our SAIDI, CAIDI and MAIFIe results annually to the Commission per Rule 25-6.0455, F.A.C., which requires the IOUs to file distribution reliability reports.

The company also tracks and sets goals around a measurement known as Customers Experiencing Multiple Interruptions ("CEMI-5"). CEMI-5 indicates the percentage of customers who experience five or more outages annually.

Q. How has the reliability of Tampa Electric's Electric Delivery system changed since 2013?

A. Our reliability has steadily improved since 2013. Our SAIDI improved from a high of 94.7 in 2018 to a low of 67.90 in 2020 and MAIFIe improved from a high of 12.16 in 2013 to a low of 7.79 in 2020. Our CAIDI improved from a high of 84.54 in 2014 to 72.23 in 2020. Document No. 2 of my exhibit reflects results since 2013 for these three indices. As a result, the company's JD Power scores have improved over recent years as I will discuss in more detail later in my direct testimony.

Q. How did the company improve its Electric Delivery system reliability?

A. Tampa Electric attributes these improvements to three major sources. The first major source is the company's robust Asset Management Program implemented in 2016. The cornerstone of this program, and the primary driver for our reliability improvements, is the distribution reliability plans we prepare each year. The second major source of improvements is operational changes such as off-shift crew staffing and improved call out and dispatch processes. Finally, the third major source of improvements is the implementation of Distribution Substation Auto Close of Tie Breaker system which is described later in my direct testimony.

Q. Please describe the annual distribution reliability plan and how it is prepared.

A. We prepare our distribution reliability plan by evaluating the reliability of each distribution circuit on an annual basis. The company considers the SAIDI, MAIFIe, and SAIFI results to determine which circuits to target for reliability improvement. We also evaluate our five-year history of circuit outages by circuit to find the most common cause and location of outages.

The results of these evaluations are used to identify the type and location of equipment needed to improve reliability and to install that equipment in places that will optimize reliability improvements. By installing new equipment, such as three phase reclosers and Trip Savers, and by making other circuit improvements, the company has been able to significantly improve its system reliability.

Q. Has the company taken other actions to improve reliability?

A. Yes. Installing new equipment is only one way to improve reliability. Operational changes have been made, such as adding troubleshooters, dispatchers, and after-hours crew staffing, each of which has helped reduce outage times when outages do occur. We have also installed a Distribution Substation Auto Close of Tie Breaker system in some substations in a way that has significantly reduced outage times.

Q. Please explain how the Distribution Substation Auto Close of Tie Breaker system works.

A. This system senses when a transformer trips due to an internal fault and then verifies that the necessary load transfer is safe and secure before automatically sending a close signal to the tie breaker. This includes verification that expected conditions are met and that the appropriate equipment is deenergized and that the added load will not overload the healthy transformer when transferred. It allows us to maximize recovery of lost load by safely transferring it to an in-service transformer in a few seconds without any manual intervention by dispatchers or field switching personnel. This system successfully recovered a portion of the Downtown Tampa area load in January 2021 after one of the transformers in the Washington Street substation tripped due to a failed low side bushing.

Q. Do you have an example of how the company’s Asset Management approach has benefitted customers?

Yes. The Substation Medium Power Transformer Doble Testing program is an example. Asset Management principles require consistent testing of critical assets to ensure they achieve their full life expectancy. We perform Doble testing approximately every five years on all medium power transformers. In the last three years, we detected seven bushing and four lightning arrester issues before they resulted in a failure. Early detection allowed for the company to plan and coordinate the necessary repairs and outages so that all customers fed from the affected transformers were offloaded to other circuits, saving approximately 60 seconds of SAIDI annually. Using the United States Department of Energy's Interruption Cost Estimate ("ICE") Calculator, this single application of Asset Management principles conferred an economic benefit to our customers of approximately $1.9 million.

Q. Have the company's system performance and reliability improvements improved Tampa Electric's customer experience?

A. Yes. Tampa Electric measures improvements to customer experience with JD Power scores, and those scores have improved significantly over the last few years.

Our JD Power ranking for residential customers' overall satisfaction has improved from the fourth quartile in 2017 to the top of the second quartile in 2020 and we are ranked in the second quartile for the Power Quality and Reliability driver.

For business customers, we are currently ranked in the first quartile for overall satisfaction and ranked in the first quartile for all drivers of satisfaction, including Power Quality and Reliability.

The company has steadily improved its national industry ranking for both residential and business customers and we are now ranked 40 out of 143 brands compared to 81 out of 142 brands in 2019 for residential and 4th out of 86 national business brands.

Since 2013, our outages are 20 percent shorter in duration (SAIDI) and our momentary outages are 36 percent less frequent (MAIFI). Both contribute to a better customer experience.

Q. How does the amount of T&D plant in rate base for the 2022 test year compare to the amount of T&D rate base in the company’s 2013 rate case?

A. In 2013, transmission plant totaled $655.4 million and distribution plant totaled $2.04 billion, for a total T&D rate base amount of $2.7 billion.

The total amount in rate base projected for our 2022 test year, and reflected in MFR Schedule B-07, includes transmission plant of $1.16 billion and distribution plant of $3.35 billion, for a total T&D rate base amount for the 2022 test year of $4.5 billion.

This amounts to an increase in transmission plant of $500.93 million, an increase in distribution plant of $1.30 billion and a total T&D rate base increase of $1.80 billion. This includes $37.94 million in SPP related transmission plant and $258.3 million in SPP related distribution plant added from 2020-2022.

Q. What major projects since 2013 are reflected in this increase?

A. The areas and projects with the largest capital investment since the company's 2013 rate case, years 2014 through 2022, include:

- $474 million in distribution system expansion to provide electric service to new residential and commercial customers. Tampa Electric served approximately 695,000 customers in 2013 and now serves approximately 800,000, an increase of about 15 percent. By 2022, we expect to serve approximately 812,000 customers, an increase of about 17 percent since 2013.

- $293 million for preventative maintenance activities on the distribution system including approximately 33,000 wooden pole changeouts costing approximately $178 million, underground cable replacements, transformer changeouts, and capacitor bank maintenance.
- $306 million for corrective maintenance activities on the distribution system, including replacing failed overhead and underground equipment and restoration activities following typical storm events.
- $242 million, including AFUDC, modernizing our metering infrastructure with new robust telecommunications, metering infrastructure, information systems and data management solutions. Collectively our new AMI system is foundational to establish new capabilities to meet customers' expectations.
- $221 million for new transmission lines and expanding existing transmission facilities needed to add the required capacity to provide electric service to new residential and commercial customers. This includes $115 million in new transmission facilities required to interconnect the new Polk Power Combined Cycle generating unit placed in service in 2017 and $27.8

million of AFUDC eligible capital for new transmission facilities required to interconnect the new Big Bend Combined Cycle generating unit to be placed in service in 2022. This investment is reflected in MFR Schedule B-13.

- $135 million to convert old outdoor lights with new, energy efficient LED Lights. This program has substantial customer support; approximately 35 percent of our customers submitted letters to the Commission in support of this program. Our LED lighting program reduces the nominal average customer bill by $0.46/month per light, reduces long-term O&M costs, results in less outages, provides automatic outage detection, and improves illumination that may help reduce crime and vehicular incidents.
- $93 million for new Lighting installations to satisfy new customer requests.
- $103 million for required facility relocations to accommodate governmental road improvement projects.
- $159 million to construct eight new substations and expand existing substation facilities needed to add the required capacity to provide electric service to new residential and commercial customers.
- $94 million for substation preventative maintenance activities including circuit breaker, relay, and

switch upgrades as well as approximately 50 spare transformer purchases. These investments were identified as part of our Asset Management Program and have substantially reduced the chances of large and extended outages, thus improving reliability and service to our customers.

- $87 million for new vehicle purchases required to maintain a reliable fleet so our crews and field personnel can provide the timely customer service expected. The company performed a fleet study in 2019 that helped optimize the number of vehicles within Electric Delivery, reducing the fleet by 68 vehicles while the number of field team members remained relatively constant. The company has been able to increase its average utilization rate while modernizing its fleet. At the end of 2018, the average age of Tampa Electric's Electric Delivery fleet was 6.87 years, which is slightly higher than the industry average of just over six years.
- $24 million to implement a new Advanced Distribution Management System ("ADMS") at our Energy Control Center ("ECC"). This will allow our Outage Management System to fully leverage the new AMI system and will also provide advanced analytic and diagnostic tools that will help us reduce customer outages and reduce

outage durations.

- Additionally, the company will continue to invest capital in its T&D facilities, that may be AFUDC eligible, and required to interconnect solar facilities. These projects and costs are described in the direct testimony of Tampa Electric witness C. David Sweat and reflected in MFR Schedule C-13.

Q. Were these plant additions prudent when made?

A. Yes. All of these investments were made to accommodate customer growth, improve reliability, respond to customer demands, or were required to comply with government requirements. The company made changes after careful analyses that considered the conditions and circumstances known at the time, safety, reliability, cost-effectiveness, and then-existing government requirements.

FUTURE PLANS FOR TRANSMISSION AND DISTRIBUTION SYSTEM

Q. Will the company need to continue investing in its Electric Delivery system?

A. Yes. Tampa Electric will need to continue investing in its Electric Delivery system to maintain the level of safety, system stability, and service reliability that our customers expect. With more than 20 million residents, Florida is one of the nation's fastest growing states, and the Tampa Bay area and I-4 Corridor are its fastest growing areas. Our future Electric Delivery capital spending to be recovered through base rates will be driven by customer growth, the need for infrastructure improvements, and governmental/regulatory commitments.

Q. Will the company's Electric Delivery system need to evolve to address changes in the utility industry?

A. Yes. Tampa Electric witnesses Archibald D. Collins, Melissa L. Cosby, David A. Pickles, and Karen M. Mincey describe how the expectations of our customers and the electric industry are changing. To meet the challenge, Tampa Electric must make long term investments in our Electric Delivery system to ensure that it will be safe, secure, reliable, synergistic with distributed generation and battery storage, and will provide the data customers want for managing their electric service. Accordingly, our long-term plans include significant investments for grid modernization. These investments support digitalizing the grid which will increase our visibility into grid operations and make data available for more efficient and effective grid operations, grid planning, new customer programs, new rate designs, and provide data directly to customers so they can better manage their electric service.

Q. What factors and trends are behind the company’s need to modernize its Electric Delivery system?

A. There are several drivers shaping our strategy to strengthen and modernize the grid.

- Our customers expect a user-friendly digital experience and the benefits of automation.
- Customers value improved reliability and expect an “always on” service level from their utility.
- Customer adoption rates for distributed energy resources are accelerating.
- Costs continue to decline for solar and battery energy storage system options both on the utility and customer side of the meter.
- Energy and transportation preferences continue to accelerate toward zero emissions.
- The adoption of electric vehicles (“EV”) continues to accelerate as nearly every major car manufacturer now has an EV offering.
- Utilities are building capabilities to extract and analyze the influx of data from an expanding suite of

enterprise systems like AMI, ADMS, Customer Relationship and Billing system ("CRB"), Geographic Information System ("GIS"), Energy Management System ("EMS"), and Enterprise Resource Platform ("ERP"). Companies are developing new data analytics to improve customer service, operations, and improve predictive maintenance practices.

- Our workforce needs a new set of digital, analytic, and technical skills to operate and maintain the information technology supporting our Electric Delivery System.
- Cyber security concerns will continue to influence how we use information technology to support our Electric Delivery system and protect against ever increasing threats.
- The company's quest for World Class Safety continues to inspire our construction and operating practices and safety is a key driver across all facets of our operations.

All these factors create pressure on our system and the electric grid will need to modernize in order to respond. The grid will need to have stability, flexibility, and digital capabilities to integrate and optimize new generation and storage resources, and the fluctuations from the mobile load of electric vehicles.

Q. How is the company planning to address these considerations and challenges?

A. We have developed and are implementing a Grid Modernization Strategy that will (1) support an "always on" customer experience; (2) build a future enabled and adaptable electric grid; and (3) operate our grid to maximize performance. Our grid modernization strategy includes initiatives and projects such as: expansion and leverage of an Asset Management program including the 2020-2029 SPP; building a robust and secure communications network; establishing micro-grids, expansion and dispatch of distributed energy resources including solar and battery storage devices; and taking full advantage of the capabilities available through our new AMI and ADMS systems.

Advanced Metering Infrastructure ("AMI")

Q. What is the company's AMI project and how does it fit into company's grid modernization strategy?

A. Our AMI project is one of the cornerstones for our grid modernization strategy and will enable the company to fully support a “Next Generation” power grid. AMI will transform Tampa Electric's relationship with its customers by delivering the choices and convenience that they have come to expect.

In simple terms, the AMI initiative involves installing advanced metering technology ("smart meters"), communication infrastructure, data management systems, and customer engagement programs and services.

We began our planning for this project in 2016 and began work in 2018. We are in the process of replacing our existing electric meters with 800,000 new AMI meters and constructing a new communication system. Our AMI communications infrastructure will include a wireless RF mesh network, cellular technology where necessary, and existing and new fiber optic infrastructure.

Tampa Electric is using an innovative deployment approach for AMI. Typical AMI deployments perform the back-office system integrations first and then deploy the AMI meter populations after the AMI back office and communication systems are in place. The company’s approach decoupled the back-office integration work and AMI meter deployment such that both activities are proceeding concurrently.

The back-office and communications systems referred to above consist of: (1) the head end, which will allow the monitoring and control of the meters remotely through a user interface; (2) network controllers which allow for the control and monitoring of the Connected Grid Routers collection devices; (3) meter data management systems which allow for the collection, storage, and validation of data; and (4) billing and support systems.

Once smart meters and the AMI communication network becomes functional, we will implement several enterprise level IT solutions. These new IT systems will enable the company to better manage operations and provide enhanced customer service and include a meter data management system ("MDMS"), increased functionality in the SAP CRB system, remote meter connect and disconnect capabilities, and analytic tools to provide enhanced operational and customer engagement capabilities.

The AMI infrastructure and its various components are illustrated in Document No. 3 of my exhibit.

Q. What role do smart meters play in the AMI system?

A. The new smart meters are replacing our old Automatic Meter

Reading ("AMR") meters. The AMI meters will provide granular, near real-time data that will enable customers to take control of their energy usage and make decisions that will lower their electric bills. The two-way communications capability of smart meters will allow the company to respond more quickly to customer service requests, and, in some cases, begin responding to "trouble" even before a customer is aware of it. The Electric Delivery team will collaborate with our Customer Experience team to provide these customer benefits and offer new customer programs and services as our AMI system becomes fully functional.

Q. When will the new AMI system be in service?

A. The company expects that its AMI system will be installed, fully functional, tested, and ready to be placed in service in December 2021. The project is currently on time and within budget.

Q. What is the projected cost of the AMI system?

A. We expect the capital portion of the AMI system to cost approximately $242 million, which is reflected in our projected rate base for the 2022 test year. We are approximately nine months from completion, all major pieces have been purchased, contracts are in place, and we expect the project to come in within budget.

Q. Is the company's projected investment in its AMI system prudent?

A. Yes. Our AMI system will provide substantial operational and customer service benefits for the company and its customers and was procured using the company's normal practices which are designed to ensure that we purchase goods and services at the lowest reasonable cost.

Q. How did the company procure the equipment and services for the AMI project?

A. We selected our major vendor for the project – Itron - using a rigorous RFP process. Itron was selected because it offered the most cost-effective solution, was known as an industry leader, had an excellent history of successful projects, and its product can be updated and improved as new applications become available. A schedule detailing the major components and projected costs for our AMI project by year is included in Document No. 4 of my exhibit.

Q. What benefits will the AMI system provide from an operations perspective?

A. The new AMI system will provide significant operational benefits for our company and our customers, including:

- The ability to collect interval meter data over the network, thereby reducing truck rolls and increasing read rates.
- The ability to remotely connect and disconnect service, leading to faster connections, fewer truck rolls and reduced call volumes in our call centers.
- The ability to identify consumption on inactive accounts, identify abnormal usage, and detect malfunctioning equipment, energy theft, and meter tampering.
- The ability to automatically detect outages and verify service restoration through near real-time notifications.
- The ability to connect and coordinate equipment to our electric grid other than meters, such as streetlights, solar, battery storage, and electric vehicles.

Other additional benefits to our customers are discussed in the direct testimony Ms. Cosby.

Q. Will there be any additional cost savings from the AMI implementation?

A. Yes. The company will further realize some reductions in meter reading expenses as well as expenses for field and meter services such as meter connect and disconnect, energy theft, and outage detection activities. However, most of the cost savings were associated with meter reading and such cost savings were realized when the company began transitioning from electro-mechanical meters to AMR meters almost 20 years ago. The AMR conversion program eliminated the need for meter readers to take manual readings at each individual meter. By converting from electro-mechanical to AMR meters, the company reduced its meter reading workforce from over 100 to fewer than 20 by the end of 2014.

Q. Will there be ongoing costs associated with the implementation of AMI?

A. Yes. After our AMI system goes in service, Tampa Electric will continue to incur costs associated with the IT systems and integration of hardware, software, development, security, management, and data analytics, as well as the ongoing maintenance of these systems. Those costs are anticipated to exceed the cost savings gained from the AMI deployment and result in a net increase in O&M expenses. These increased costs are required to provide the benefits and improve our customer experience.

Q. Is the replacement of AMR meters and their early retirement prudent?

A. Yes. The replacement of the company's AMR meters and associated retirement on December 31, 2021 is prudent. As previously described in my direct testimony, the new AMI system is a key part of the company's grid modernization strategy and will provide Tampa Electric's customers with a wide range of new benefits. These new benefits would not have been possible utilizing existing AMR meters, as such, the retirement of the AMR meters is prudent.

OTHER FUTURE ELECTRIC DELIVERY PLANS

Q. What other Electric Delivery system improvements are being planned to implement the company's grid modernization strategy?

A. We will continue to focus our efforts on programs and projects to further reduce outages, outage times, and, as a result, improve overall customer satisfaction and experiences. Some of the innovative projects being planned or implemented in the Electric Delivery include:

1. Implement Distributed Energy Resources ("DER") aggregation capabilities. Tampa Electric's control systems do not currently have the capability to aggregate, monitor or control DERs. This future initiative will ensure our grid systems can safely integrate DERs into grid operations, planning, and optimization, helping us better serve our customers.

2. Implement AMI grid edge applications. One of the reasons we selected Itron as our AMI vendor was its leading position in the industry on grid edge data analytics. Our AMI system will give us the ability to gather and use a tremendous amount of new data to improve reliability and offer new services to customers. These grid edge applications will allow us to use data more efficiently by analyzing it directly in real time at the meter and are planned for deployment beginning in 2023.

3. Enable Smart City capabilities. Our AMI system infrastructure and mesh network give us the capacity to partner with local governments to support broader community goals and enhance existing services. We are working to develop applications in the areas of gunshot detection;

stormwater detection; traffic and pedestrian counting; and surveillance. For example, the City of Tampa most recently expanded their gunshot detection pilot which will attempt to detect gunshots within a multiple block area by using over 100 sensors that are attached to Tampa Electric poles. Hillsborough County is working on a Vision Zero initiative to have zero pedestrian, bicycle, and vehicle fatalities. Our AMI system is well positioned to enable and support important community projects like these.

4. Implement EV pilots and technology advancements. The company will initially serve in a facilitation role in the EV market as it continues to grow and evolve. Proper grid planning is critical to ensure reliability and develop our internal competencies to provide long-term support of the local market. The company has requested Commission approval of a four-year public EV charging pilot to deploy up to 200 charging ports across our service territory. This pilot, if approved, will allow us to develop a better understanding of EV charging infrastructure, charging behavior data, and how EV charging affects the operation of our grid. This pilot will benefit our customers by providing greater access to public charging, the lack of which is recognized as a significant barrier, whether real or perceived, to the adoption of EVs. The company currently

plans to invest approximately $2.2 million on this initiative by year end 2022.

5. AC/DC neighborhood microgrids. Tampa Electric and its affiliate Emera Technologies LLC ("ETL") are working with Lennar Homes Inc ("Lennar") to install an innovative Direct Current Microgrid Pilot Program ("Pilot") in southern Hillsborough County. The Pilot involves installation of new direct current ("DC") electric microgrid technology and associated generating equipment, known as the Block Energy System, to provide power to approximately 37 homes. The Pilot will test the capability of the Block Energy System to power residential homes in Florida with a high level of renewable energy as well as superior reliability and resiliency. The Commission is considering this Pilot in Docket No. 20200234-EI.

Q. How will the plans described in this section of your direct testimony benefit the company and its customers in the future?

A. The company and its customers will benefit from these plans in numerous ways, including:

- Customers will be able to realize the benefits of automation through a wide-ranging user-friendly digital experience.

-
- Customers will have fewer and shorter outages through the operations of Fault Location Isolation and Service Restoration ("FLISR") and pro-active maintenance programs using enhanced data analytics.
- Customers will have fewer momentary outages.
- Customers will enjoy improved storm recovery times because of the SPP Program and other Grid Modernization resiliency programs.
- Customers will be able to use clean distributed energy resources in a "plug and play" way.
- The company will be able to support accelerated EV adoption rates.
- Customers will benefit from the company's capabilities to forecast, schedule, and operate an extensive portfolio of cost-effective distributed energy resources.
- The changes will further advance the ability to improve our environmental footprint and reduce carbon emissions through greater use of zero and low-carbon generation, storage, and transportation technologies.

2022 CONSTRUCTION PROGRAM AND CAPITAL BUDGET

Q. What are Tampa Electric's projected capital investments for Electric Delivery in 2021 and 2022?

A. As shown in Document No. 5 of my exhibit, the non-SPP related capital investment projections for the Electric Delivery area totals $320.2 million in 2021 and $263.4 million in 2022. This total is comprised of $242.2 and $225.3 million for sustaining capital projects and $77.9 and $38.1 million for strategic capital projects in 2021 and 2022, respectively. These additions to rate base are prudent as described below.

Q. How does Tampa Electric determine the construction program and capital budget for additional T&D facilities?

A. Tampa Electric determines its construction program and capital budget for major additional T&D facilities through its annual system planning and capital planning process. This process and the resulting capital plan are intended to ensure that management is aware of proposed future spending requirements, the expected benefits to both customers and the organization, and the impacts and or risk of not making the proposed investments. The capital planning process results in a prioritized list of T&D projects for the current fiscal year capital budget and the five-year capital plan, as well as the capital budgets for smaller T&D additions, maintenance, restoration, and other T&D related capital activities.

Q. How does the company plan and manage its major T&D capital improvement projects?

A. The company plans to meet the future requirements of all customers served from its T&D systems using system models and well-established T&D planning criteria. We use internal models and standards to ensure that the most cost-effective distribution projects are identified. We also use local and regional models and standards to identify transmission projects.

Once the projects and all alternatives considered are fully reviewed and approved as previously described, the company's Electric Delivery Project Management team is responsible for coordinating with all required engineering and operations groups to develop detailed schedules and budgets for managing all major T&D projects until they are placed in service.

Q. You previously explained the company's T&D plant rate base additions from 2013 to 2022, why they were prudent, and that they continue to be used and useful to serve the company's customers. Would you now please describe and explain the additions to T&D plant rate base forecasted to occur in the 2022 test year?

A. The total increase in the company's related T&D plant rate base forecasted to occur in the 2022 test year amounts to $404.96 million, including $94.22 million in transmission plant and $310.74 million in distribution plant as reflected in MFR Schedule B-07. This includes $16.50 million in SPP related transmission plant and $141.66 million in SPP related distribution plant to be added in the 2022 test year.

Q. What major projects are included in these amounts and why are they prudent?

A. In general, these major projects are required to maintain Tampa Electric's high level of reliable service while simultaneously addressing aging infrastructure. Some of the other T&D initiatives are critical to ensure reliable operations, some are to improve customer satisfaction, and some are required to meet regulatory requirements. All will provide benefits to our customers.

Some of the major areas and projects planned for 2022 are described in MFR Schedule F-08 and below with their benefits:

- $58 million for distribution system expansion required to reliably serve new customers.
- $24 million for preventative maintenance activities on the distribution system including wooden pole changeouts, underground cable replacements, transformer changeouts, and capacitor bank maintenance. These preventative maintenance activities will ensure that the work can be planned and performed more cost effectively than reactively when a failure was to occur. This will also prevent unnecessary customer outages.
- $33 million for corrective maintenance activities on the distribution system including replacing failed overhead and underground equipment and restoration activities following typical storm events.
- $23 million for new transmission lines and expanding existing transmission facilities needed to add the required capacity to provide reliable electric service to new residential and commercial customers.
- $28 million to advance our LED Lighting conversion program. This is a continuation of the well-established program and meets the demands of our customers for reliable efficient LED lighting. The benefits of this

program include lower electric bills for our customers, lower O&M expenses for the company, fewer outages, and improved illumination that may reduce crime and vehicle accidents.

- $11 million for new Lighting installations to satisfy new customer requests.
- $8 million allocated to execute the early stages of the Grid Modernization strategy. These expenditures are to construct a private LTE communications network needed for a reliable, resilient, and modern grid and to establish the IT systems required to support our future line sensing technology infrastructure.
- $10 million to relocate our T&D facilities located in public rights-of-way in conjunction with governmental road improvement projects.
- $33 million for new substations and to expand existing substation facilities to add the required capacity to provide reliable electric service to new residential and commercial customers.
- $7 million for substation preventative maintenance activities including circuit breaker, relay, and switch upgrades as well as approximately 50 spare transformer purchases. These investments were identified as part of our Asset Management Program and will significantly reduce the chances of large and extended outages,

thereby improving reliability and service to our customers.

- $9 million for new vehicle purchases required to maintain a reliable fleet so our crews and field personnel can provide timely customer service.

Q. Is the any property being held for future T&D use?

A. Yes. As reflected in MFR Schedule B-15, the company is holding property for future T&D use. Specifically, the River to South Hillsborough corridor will be used for future 230kV facilities driven by the need to continue to reliably serve Tampa Electric's existing load and future load growth and the company's adherence to existing NERC Reliability Standards. In addition, we have property located at Big Bend Road and US 41 that is adjacent to the Big Bend power plant and is being held for a possible future substation, site expansion, or renewable generation project.

2022 TRANSMISSION AND DISTRIBUTION O&M EXPENSES

Q. What are Electric Delivery's O&M expenses budgeted for 2022 and how has the amount varied since 2013?

A. Document No. 6 of my exhibit shows Tampa Electric's

Electric Delivery department expenses (excluding all activities related to storm hardening and SPP as those costs are now recovered through the SPP cost recovery clause) from 2013 to 2022. The budgeted amount in 2022 is $71.8 million.

Q. How does the adjusted 2022 test year total T&D O&M costs per company books compare with the Commission O&M benchmark?

A. As described in the direct testimony of Tampa Electric witness Jeffrey S. Chronister and reflected in MFR Schedule C-37, the company's adjusted 2022 total T&D O&M costs are expected to be under the benchmark by $9.1 million. Specifically, the adjusted test year total T&D O&M per company books in 2022 is $57 million. The adjusted test year total T&D O&M benchmark in 2022 is $66 million. This includes a favorable variance of $6.1 million in transmission related expenses and a favorable variance of $2.9 million in distribution related expenses. This favorability can be attributed to continuous improvement initiatives within Electric Delivery as well as the implementation of Asset Management and Grid Modernization programs.

Q. Was an adjustment made to the O&M expenses for benchmark modeling, and if so, how much?

A. Yes. To obtain an "apples to apples" comparison, an adjustment was made for the storm protection plan related activities. We adjusted the test year by $26 million and the base year by $11.5 million. The SPP adjustments for the test year are shown in MFR Schedule C-38 and the adjustments for the base year are shown in MFR Schedule C-39. The adjusted T&D O&M benchmark calculation is shown in MFR Schedule C-41 and shown in Document No. 7.

Q. How has development of the company's SPP and implementation of the related SPP cost recovery clause affected the amount of T&D O&M expense to be recovered through base rates?

A. As part of the SPP, the company shifted several legacy storm hardening activities into SPP programs. Cost recovery of the O&M expenses associated with these activities was also shifted from base rates to the SPP cost recovery clause. These activities and costs included vegetation management, pole inspections, and transmission structure inspections.

Q. What are the main drivers for the company's Electric

Delivery's related O&M expenses.

A. The main drivers for Electric Delivery's O&M expenses are maintenance expenses, meter services, restoration, and load dispatching costs. Document No. 8 of my exhibit reflects Electric Delivery's O&M expenses for the test year 2022.

Maintenance expenses include the costs associated with non-SPP related equipment inspections, condition-based substation preventative maintenance, downtown Tampa network inspections, and activities to correct or repair non-operable or unsafe conditions on the system that have been identified through a non-SPP inspection.

Meter services expenses include remotely reading and managing disconnection and reconnection services; meter testing; servicing meters; and meter installation.

Restoration expenses reflect the costs of activities associated with patrols, switching, and repairing facilities that have failed and are required to restore service to customers. These costs are incurred due to weather or other causes/events that result in equipment failure.

Control Center dispatch expenses include the costs of activities related to operating the balancing area and the bulk electric transmission system and costs required to operate the distribution network.

Q. What major factors have contributed to an increase in total O&M spending in the Electric Delivery area?

A. Although Electric Delivery is below the O&M benchmark, it should be noted there are a few areas that have seen increases in O&M spending. Operation and maintenance of the IT and communication components of our AMI system requires additional software and team members with new and different skill sets. Separate and apart from our SPP activities, we are spending more resources to improve our Emergency Preparedness. Our internal labor and contract labor costs have increased and outpaced CPI due to market conditions with limited skilled workers and extremely high demands for their services. The cost of using outside contractors has increased due to the increased demand in resources needed to implement the various SPPs across the state. We have moderated these increases by developing a work culture that focuses on continuous improvement and efficiency and has resulted in cost control and cost reduction measures, some of which are described below.

Q. What safety initiatives are reflected in T&D O&M expenses for the 2022 test year and why are those initiatives beneficial for customers?

A. Following the SMS previously described in my direct testimony is one of the cornerstones of Electric Delivery's operations. The SMS is designed to ensure compliance with OSHA regulations and is aligned with OSHA recommended practices. The requirements and programs of each element are embedded in the operating costs of the business. By implementing a SMS, the company is not only promoting the safety of its team members, but also its customers and the public.

Our SMS program benefits our customers in several ways, including fostering a safety-first culture that promotes working safely and ensuring the electric service provided is safe, reliable, and cost effective. As previously noted, the number of work-related injuries reported annually within Electric Delivery has decreased by 53 percent since 2013 as a result of the safety initiatives implemented.

Q. Please describe the change in outside professional services for the historical and projected test year.

A. As noted in MFR Schedule C-16, Electric Delivery's outside professional services costs have declined since 2020 in the areas of contractors and consultants while our Line Clearance costs have increased. Line clearance costs are higher due to increased tree trimming activities associated with the SPP which will be recovered through the SPP cost recovery clause. Consultant and contractor costs are lower due to efficiencies and reduced dependency on field contractors, as well as lower use of consultants, which assisted in process improvement initiatives and SPP plan development in 2020.

Q. What steps has Tampa Electric taken to control T&D O&M costs while maintaining a safe and productive workplace?

A. First and foremost, the company and Electric Delivery have developed a culture of continuous improvement. This culture and approach help control O&M cost pressures without sacrificing safety. The company has also implemented numerous cost savings initiatives since our last rate case in 2013.

Our Asset Management program has played a critical role in controlling Electric Delivery O&M expenses by ensuring that the right assets are maintained, repaired, or replaced at the right time to eliminate outages, customer impacts and expensive unplanned maintenance activities. The use of technology has helped control O&M costs. For example, the company has implemented a new call out system, ARCOS, which significantly improved our call out response times, thereby reducing outage times and restoration costs. The company has also upgraded its Field Dispatch software, PCAD, which has provided more capabilities to our troubleshooters, again reducing outage times and restoration costs. In addition, the company has started using drones for transmission inspections, which is less costly than traditional helicopter patrols. Finally, optimizing field crew schedules has allowed for increased productivity and safety while reducing restoration costs.

Some other continuous improvement initiatives that have helped manage costs include:

- Grid Operations implemented new solar forecasting and dispatch tools to optimize the use of solar generation.
- Warehousing implemented a new barcoding system in 2020 to ensure better inventory controls and provide real-time information on inventory levels.

Q. Is the overall level of T&D O&M expense for 2022 reasonable?

A. Yes. The proposed O&M expenses for 2022 are reasonable and support those activities required for system operations and restoration, inspection programs, maintenance of equipment and computer systems, meter services, and required compliance activities.

The company's culture of continuous improvement has generated many initiatives and cost control measures that have been implemented from 2013 to 2020. These have helped mitigate cost pressures in several areas, including the higher labor rates and contractor costs that have outpaced inflation due to market conditions and increased demand for a limited supply of utility workers.

Our current O&M expense levels have allowed Tampa Electric to maintain and improve its system reliability and customer experience. The company's five-year SAIDI average ranks second in the state when compared to our peers and is in the top quartile when compared to other Southeastern utilities. Our MAIFIe, or momentary interruptions, have decreased by 36 percent since 2013. The reliability and the resulting operational and customer service improvements can be attributed to our implementation of Asset Management Program principles in the Electric Delivery area.

SUMMARY

Q. Please summarize your direct testimony.

A. Tampa Electric forecasts that it will invest $260.6 million in Electric Delivery capital and incur $71.8 million in Electric Delivery O&M expenses for the 2022 test year.

Electric Delivery's proposed T&D budgets support and align with the company's strategic priorities. Our capital budget includes investments for the transmission, distribution, and substation expansion and upgrades needed to support customer growth, maintain system reliability and resiliency, replace aging infrastructure, improve our customers' experience, and meet our governmental and regulatory commitments. Our 2022 forecasted O&M amounts will support the activities required for system operations and restoration, inspections, maintenance of equipment and computer systems, meter services, and required compliance activities. Electric Delivery's continuous improvement initiatives and cost control measures implemented from 2013 to 2020 have resulted in O&M spending below the expected levels despite increased costs from newly implemented AMI software, additional Emergency Management support, and higher labor rates and contractor costs that have outpaced inflation due to market conditions and increased demand for a limited supply of utility workers. This is reflected by the T&D O&M expenses for the 2022 test year being $9 million below the Commission's Benchmark.

Tampa Electric has significantly improved its system reliability. The company's five-year SAIDI average ranks second in the state when compared to our peers and is in the top quartile when compared to other Southeastern utilities, while our MAIFIe, or momentary interruptions, have decreased by 36 percent since 2013. Both improvements can be attributed to the robust Asset Management Program Electric Delivery has implemented and putting systems and personnel in place to minimize outage times when outages do occur.

The company's grid modernization efforts described in my direct testimony, including AMI, are reasonable and prudent and are necessary to meet the future demands of our customers and electric industry changes. All of these projects will provide real benefits to our customers.

Overall, Tampa Electric's proposed T&D capital and O&M budgets for 2022 represent a strategic and balanced approach that will provide the modern grid required to meet our customers' increasing expectations at a reasonable cost and should be approved.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Karen M. Mincey was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI
IN RE: PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

KAREN M. MINCEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN M. MINCEY

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

A. My name is Karen Mincey. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Vice President – Information Technology and Telecommunications and Chief Information Officer.

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

A. I am responsible for the company's Information Technology and Telecommunications ("IT") department vision, leadership, and direction to (1) achieve strategic technology and business objectives and (2) monitor the company's competitive positioning with respect to IT services. I oversee all enterprise-wide IT activities, including infrastructure, architecture, cybersecurity, applications development and support, networks, sourcing, and computer and auxiliary operations. I also (1) ensure that the appropriate information protection measures are applied to corporate and customer data while meeting legal and regulatory requirements and (2) develop and manage the company’s comprehensive business continuity plan for emergencies that could affect its computing systems and operations.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of New Orleans and a Master of Business Administration degree from Loyola University (New Orleans). I worked for Entergy New Orleans in various engineering and project management roles for eight years. I joined Tampa Electric in 1990 and have worked in Commercial and Industrial Marketing, Distribution Engineering, Telecommunications, and Information Technology.

Q. What are the purposes of your direct testimony?

A. The purposes of my testimony are to describe: (1) the company’s IT Department; (2) the IT resources and applications Tampa Electric uses to operate its electric system and provide an outstanding customer experience; (3) how the company has transformed its IT infrastructure and processes since its last rate case in 2013; (4) the company's 2022 IT capital budget; and (5) the company's 2022 projected test year IT operations and maintenance ("O&M") expenses.

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

A. Yes. Exhibit No. KMM-1, entitled "Exhibit of Karen M. Mincey," was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of the following two documents:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Karen M. Mincey
Document No. 2	Table summarizing major IT projects since 2013

Q. Are you sponsoring or co-sponsoring any sections of Tampa Electric's Minimum Filing Requirements ("MFR") schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR Schedules listed in Document No. 1 of my exhibit.

IT DEPARTMENT OVERVIEW

Q. What are Tampa Electric's major areas of strategic focus?

A. As noted in the direct testimony of Tampa Electric witness Archibald D. Collins, the company's three areas of strategic focus are safety, cleaner and greener operations, and an outstanding customer experience. The company's IT department plays a vital role in supporting these areas.

Q. How does the IT department provide support in these areas?

A. The IT department supports safety by providing technology that allows employees to record and track personal safety information and personal safety reports. Our department supports cleaner and greener operations by providing technology solutions that enable employees to efficiently monitor and control the generation and distribution assets that we use to operate the electric grid and deliver power to our customers. Finally, the IT department helps provide an outstanding customer experience by implementing and providing ongoing support for the systems and technology solutions that customers use to request services and manage and pay their bills.

Q. Please describe the company's IT department.

A. The company's IT department will have approximately 235 team members in 2022. Our O&M expense and capital budgets at Tampa Electric for 2022 are $30.5 million and $27.5 million, respectively. The projects reflected in the IT department's capital budget benefit multiple parts of our company. If a capital project benefits only one department, then that cost is usually reflected in the budget of the sponsoring department.

The IT department has eight functional areas. Four address the process for implementing IT resources: (1) planning, (2) innovating, (3) building and monitoring, and (4) operating. The others are organized around the three major functional areas of the company (Energy Supply, Electric Delivery, and Customer Experience), the Tampa Electric corporate support functions and support for the affiliate gas companies Peoples Gas System and New Mexico Gas Company. This structure allows us to synchronize our activities with the needs of those departments and affiliates.

Q. What services does the IT department provide to Tampa Electric?

A. The IT department provides the entire slate of IT services to Tampa Electric, including IT strategy and leadership; enterprise desktop support; service desk and access administration; application development and support; IT project management; IT infrastructure services (computers, storage, networking, and telecommunications); enterprise resource planning suite support; customer relationship management and billing suite support; IT asset and vendor management; IT compliance; and cybersecurity.

Q. What IT services does Tampa Electric's IT department provide to affiliates?

A. Tampa Electric provides the same slate of IT services listed above to Peoples Gas System, our Florida natural gas affiliate. Tampa Electric provides IT strategy and leadership; service desk and basic access administration; enterprise resource planning suite support; IT compliance; and cybersecurity for New Mexico Gas Company. Tampa Electric provides desktop support as needed, enterprise resource planning suite support, and cybersecurity consulting services for Emera Technologies Limited. All costs noted in this testimony are those to Tampa Electric, unless otherwise noted.

Q. What IT services are provided to Tampa Electric by other Emera Inc. ("Emera") companies?

A. Emera provides Tampa Electric with high-level IT strategy as well as cybersecurity policy governance.

Q. Does Tampa Electric obtain services from TECO Services, Inc.?

A. No. Tampa Electric no longer receives services from TECO Services, Inc. ("TSI") because that entity no longer serves as a centralized services company. The functions it performed are now being provided by Tampa Electric business areas.

TSI was formed as a centralized service company on October 18, 2013, in anticipation of TECO Energy, Inc.'s ("TECO") closing of its acquisition of New Mexico Gas Company during the following year. After that acquisition closed, and as of January 1, 2015, TECO no longer met the Federal Energy Regulatory Commission's ("FERC") requirements to be considered a single state holding company. However, as part of that transition, and in response to a joint waiver request of TECO and Tampa Electric, the FERC agreed that, other than a few relatively minor services, all non-power goods and services provided by Tampa Electric would be transitioned to TSI. These services included: Information Technology and Telecommunications, Human Resources, Legal Services, Corporate Security, Emergency Management, and Procurement.

Emera acquired TECO Energy on July 1, 2016, and TSI continued operating until January 1, 2020, at which time TSI ceased operating as a centralized service company. The non-power goods and services it formerly provided were transferred to Tampa Electric and thereafter provided by the company to its affiliates.

Q. Was the dissolution of TSI in the best interests of the company and its customers?

A. Yes. The reorganization described above simplified our corporate structure and allowed us to capture the efficiency benefits associated with providing non-power goods and services within the TECO family under "one roof." Since Tampa Electric was the primary consumer of these non-power goods and services, it was more efficient, cost-effective, and prudent to house them within the company. The FERC agreed and granted Tampa Electric's waiver request on October 30, 2019, which allowed the company to become the provider of all non-power goods and services to its affiliates as of January 1, 2020.

IT RESOURCES AND APPLICATIONS

Q. What major IT applications support customer experience activities?

A. The core of the company's application support for customer experience activities is our Customer Relationship Management and Billing ("CRB") system, which became operational in 2017. The CRB system works with other application suites to provide an outstanding customer experience. These other application suites such as the Contact Center Management and Interactive Voice Response ("CCM/IVR") suites and the company's online customer self-service portal ("customer portal") allow customers to contact the company by telephone, computer, and mobile devices to interact with the CRB system without agent assistance.

Q. What are the major components of the CRB system and what do they do?

A. The major components of the CRB system include managing customer accounts, billing, payment, credit, and collection services. The CRB system was implemented in 2017 and replaced the company's legacy billing system; it integrates directly with many critical systems, allowing for a robust customer experience that enables customers to transact with the company when, where, and how they want.

For example, the CRB system integrates with the company's CCM/IVR system, allowing customers to obtain service over the telephone without having to speak to an agent. If the customer chooses to interact with the company by computer or mobile device, our customer portal allows customers to pay bills, report outages, start, stop, or transfer service, report lighting outages, or enroll in a variety of customer programs, *e.g.*, billing and payment programs or energy efficiency programs.

The CRB system also integrates with the company's Outage Management System ("OMS"), allowing customers to report an outage and receive the latest outage updates based on the customer's communication preferences.

Finally, beginning January 1, 2022, the CRB system will integrate with our Advanced Metering Infrastructure

("AMI") system to collect customer usage information and provide automated connections or disconnections for customers.

Tampa Electric witness Melissa L. Cosby will further describe in her direct testimony how AMI will improve the experience we provide to our customers, as well as describe the customer benefits associated with the CRB system implementation.

Q. What major IT applications support Electric Delivery activities?

A. As noted in the direct testimony of Tampa Electric witness Regan B. Haines, the company is modernizing its electric transmission and distribution grid to be more efficient and reliable, and to provide new services that will enhance the experience we provide to our customers. Improving and adding new IT resources are a vital part of that effort.

The Energy Management System ("EMS") is the core application suite for electric grid operations.

Beginning in 2021, EMS will interface with a new Advanced Distribution Management System ("ADMS"). Our ADMS will coordinate and operate Distributed Energy Resources ("DER"), intelligent distribution controls, and other smart grid operating technology.

Beginning in December of 2021, our new AMI system will interact with the CRB system to create operational efficiencies and improve customer services. Mr. Haines provides detailed information about the operational aspects of this system and its capabilities in his direct testimony.

Our Electric Delivery department uses Work Management System ("WMS") and Geographic Information System ("GIS") application suites to efficiently plan and dispatch team members and contractors to maintain, operate, and repair our transmission and distribution assets.

Our Electric Delivery department uses an application known as Street Light Vision ("SLV") to support the company's growing smart light-emitting diode ("LED") streetlight operations. Mr. Haines also describes the operating efficiencies associated with our LED program in his direct testimony.

Q. What major IT applications support the company's Energy

Supply activities?

A. The major IT application that supports Energy Supply is a Work & Asset Management System that is used to efficiently schedule work and manage materials used at the various Energy Supply sites.

Q. What major IT applications enable the company to comply with legal and regulatory requirements?

A. As discussed further below, how we have invested in, and the costs we have incurred for IT have been influenced by requirements of the FERC, the North American Electric Reliability Corporation ("NERC"), and the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley" or "SOX"), as well as increased cybersecurity and customer privacy demands.

We operate the following key applications to address legal and regulatory compliance and cybersecurity concerns: the Security Information and Event Management ("SIEM") system; Identity and Access Management ("IAM") systems; physical access control systems; multi-factor authentication ("MFA") systems; software patch maintenance and deployment systems; anti-malware systems; governance, risk, and compliance ("GRC") systems; the configuration management database ("CMdb") system; business continuity management system; an IT service management system ("SMS"); security configuration management tools; vulnerability scanning and management systems; and a risk management tracking and reporting system. Each of these systems either meets a specific regulatory requirement for security or is part of the overall defense-in-depth architecture we have established to protect customer information and the company's systems and data.

Q. What other major IT applications does Tampa Electric use and what purposes do they serve?

A. The other two major application systems supported by the IT department are the Enterprise Resource Planning ("ERP") system and the Energy Trading and Risk Management ("ETRM") system. ERP modules support business functions such as Finance, Human Resources, and Procurement. The ETRM system supports the company's energy trading and risk management activities. The IT department also supports a myriad of smaller applications for the company, such as collaboration and office productivity applications, *e.g.*, Microsoft Office and Teams, and data analytics tools.

IT INFRASTRUCTURE AND PROCESS TRANSFORMATION

Q. Has the company changed its approach to providing IT services since the company's last rate case in 2013?

A. Yes. Since the company's last rate case in 2013, we have changed our basic approach for delivering IT services to the company.

In 2013, Tampa Electric used a single highly centralized mainframe computer located in its Ybor Data Center to run its 30-year-old customer billing and support system, which was the last of our legacy corporate systems. We replaced this legacy system in 2017 with over 200 integrated computer servers distributed across various company facilities. This distributed architecture has allowed us to update our systems more efficiently when the needs of our users change, and new technology becomes available. They also allow us to provide IT solutions to our users that are more closely tailored to their ever-changing needs.

We also now use geographically dispersed "cloud-based" technology systems located in different parts of North America. These cloud-based technologies allow us to obtain and manage the growing computing power required by newer data-intensive systems. The shift to cloud-based resources has caused our cost profile to shift from capital to expense, because the annual costs associated with cloud-based resources are largely expense, not capital, under applicable accounting standards. Cloud-based resource costs have gone from a negligible portion of the IT maintenance budget in 2013 to approximately 25 percent in 2020.

Q. Why did Tampa Electric change its IT infrastructure as described above?

A. There are several reasons. The first is general changes in IT technology and the development of cloud-based computing. The network architecture changes we made reflect a world-wide trend away from large mainframe computers to a distributed network supported by cloud-based resources that can support a faster rate of change for new capabilities and functionality, which ultimately benefits the company and its customers.

Second, we have invested significantly in IT resources to meet the changing and increasing expectations from our customers. As Ms. Cosby explains in her direct testimony, the way companies like Amazon use technology to interact with their customers has changed the expectations of our customers. We have worked diligently to give our customers the ability to communicate with the company (billing questions and service changes) and access information (usage and outages) when (24-7) and how (phone, on-line, and mobile) they want to.

Third, the way we have updated and designed our IT systems, and our increased level of spending on them, was influenced by increasing regulatory, security, and privacy demands. As our reliance on information technology has increased, so too has our need to ensure that our data and systems and the information we have about our customers are secure and protected from cybersecurity threats.

Q. How have regulatory, security, and privacy concerns influenced the delivery of IT services?

A. The requirements of FERC, NERC, and Sarbanes-Oxley, as well as increased customer cybersecurity and privacy demands, played a major role in the evolution of Tampa Electric's IT system.

Q. What are the key regulatory cybersecurity requirements, and what has the company done to address them?

A. The primary IT regulatory requirements are contained in NERC Critical Infrastructure Protection ("CIP") Standards 002 through 011 and 013. These standards are intended to mitigate cyber or physical threats to the bulk electric system (*i.e.*, the electric grid). The foundation of the company's NERC compliance efforts has two parts, its "governing committee" and its general IT compliance process.

Q. Please describe the governing committee.

A. The company created an internal governing committee to address the CIP standards when they first went into effect, prior to 2013. This governing committee consists of team members from the IT department, the Regulatory Affairs department, and the affected operating areas, *i.e.*, Energy Supply, Electric Delivery, Corporate Security and Procurement. The committee ensures that our IT system and procedures allow our operating departments to comply with enforceable CIP standards. The committee also: (1) promotes awareness of current and future proposed standards, (2) ensures that new or amended standards or requirements are properly implemented, (3) coordinates and facilitates CIP audits when they occur, and (4) promotes a company-wide culture of CIP compliance.

Q. How does the company's overall IT compliance program reinforce CIP compliance?

A. Our overall IT compliance program reinforces CIP compliance in many ways:

- Compliance with regulations is part of our Code of Business Conduct.
- Our Ethics and Compliance team has developed a cross-departmental register of all compliance programs and requires confirmation of compliance each quarter by the 'program manager,' including NERC CIP.
- Our Regulatory Affairs department has a Federal Energy Compliance Program which includes designation of a Compliance Program Coordinator ("CPC") for each business area, including NERC CIP.
- We integrated the CIP requirements into our IT Standards and Procedures ("S&P"). The compliance deliverables are listed in the IT S&P, and we have created automated notifications associated with each deliverable and an escalation process to ensure these deliverables are completed on time. The deliverables are reviewed each period by the CPC.
- We identified and implemented internal controls for each CIP requirement and proactively seek additional controls.

- Tampa Electric monitors NERC standard revisions and provides comments during the appropriate development stages; we begin planning based on the likely impact of those revisions or new standards. We also monitor NERC guidance and other documents as they are issued to determine whether any enhancements to the NERC CIP compliance requirements are necessary.
- The company participates in a state-wide CIP compliance group and chairs the monthly discussions for current event updates and information sharing with other utilities.

We also are planning additional compliance-related training for various CIP stakeholders. In the case of any non-compliance issues, we also ensure that a new preventive control is added as part of the mitigation.

Q. Please describe the Sarbanes-Oxley ("SOX") requirements and controls implemented by the IT department.

A. The SOX requirements involving IT fall into the following control areas: entity level controls, acquisition or development of application software, technical change management, ensuring system security (*e.g.*, logical access administration), and data management (*e.g.*, backup and recovery). We implement these control requirements through our IT S&P for each SOX application.

In 2018, we formed a working group composed of team members from IT, Emera Audit Services, Finance, Human Resources, and Customer Experience to review existing SOX controls and identify and remediate any gaps or potential weaknesses in SOX application access or separation of duties controls. This working group recommended improvements to the company's access control processes and reporting capabilities and enhanced the GRC module in the ERP suite, which was fully implemented in 2020.

Q. How have customer information security concerns influenced the way the company delivers IT services?

A. Our customers are very concerned about data privacy and expect that the electric service we provide to them will not be disrupted by a cybersecurity event. To address these concerns, the company has continued to improve the capabilities and maturity of its cybersecurity program by increasing the number of team members dedicated to cybersecurity and investing in their skills, purchasing and installing advanced security tools with increased functionality, and implementing new processes to mitigate identified cybersecurity risk areas.

Q. How do cybersecurity concerns and threats influence the way the company delivers IT services?

A. We take cybersecurity concerns and threats very seriously. The company has a comprehensive cybersecurity program to address our due diligence efforts in this area. There are 11 FTEs dedicated to the National Institute of Standards and Technology ("NIST") prescribed best-practice functions of identify, protect, detect, respond, and recover. Utilizing a defense-in-depth methodology, the program uses a combination of best-of-breed technology tools and best-practice processes to provide around-the-clock protection and response to the thousands of daily intrusion attempts at the company. The company also implemented an IT culture of security, ensures that cybersecurity risks are considered for all services that IT delivers, and embeds risk mitigations into the service delivery.

Q. What IT investments has the company made since 2013 to improve the customer experience?

A. Since our last rate case in 2013, we have made significant investments in the company's IVR, CCM, and CRB systems.

These investments have promoted efficiencies, improved ease of use, and provided new features and services to our customers. Additional detail regarding these investments is provided later in my direct testimony and in the direct testimony of Ms. Cosby.

Q. How have these IT investments contributed to the company's rate base growth since its last rate case in 2013?

A. Document No. 2 is a table summarizing the major IT projects Tampa Electric has invested in since 2013, the business justification of the projects, and the total actual cost (current budgeted costs if in the future) of each project that contributed to the company's rate base growth by a total of $390.8 million. Each of these projects were needed to improve customer service, comply with regulatory requirements, or address a technology lifecycle issue and were executed using the company's normal procurement processes that ensure that we purchase goods and services at the lowest reasonable cost. It is important to address technology lifecycle issues to maintain access to original equipment manufacturer ("OEM") support, updates, security patches, and repair parts to avoid impacts to the delivery of business services to customers. Several of these projects, and others, are discussed in the direct testimony of Ms. Cosby.

A summary of our IT projects by year, capital cost, and benefits follows. Unless otherwise noted, the capital cost does not include AFUDC.

- 2014 – Contact Center Management ($5.2 million). This project consolidated the IVR technologies used by Tampa Electric and Peoples Gas System and created efficiencies and a common experience for customers served by both utilities.

- 2015 - Windows 10/Laptop Replacement ($4.5 million). This project upgraded all company team member systems to the latest version of Microsoft Windows and standardized equipment. It gave our team members stable and secure IT platforms and allowed us to streamline our internal support processes.

- 2016 - Energy Trading and Risk Management ($12.0 million). This project consolidated several key functions provided by separate systems and improved the efficiency of this business function. The use of a single system improved controls, reduced staffing, lowered software maintenance cost, and expedited the month-end closing processes.

- <u>2016 – Energy Management System ($8.4 million)</u>. This project upgraded the core application the company uses to operate its electric grid to a version that will be supported in the future. It included user interface improvements, multiple cybersecurity control improvements and improved NERC CIP compliance related functionality.

- <u>2017 – Customer Relationship Management & Billing ($83 million including AFUDC)</u>. This project replaced legacy technologies with a single, integrated modern suite of applications, enabled the company to provide new functions and features to its customers, and increased operating efficiencies in the Customer Experience department. Ms. Cosby explains the many benefits of the CRB system and the subsequent enhancements (beyond the $83 million in-service amount) in her direct testimony.

- <u>2019 – Unified Communications System ($3.0 million)</u>. This project upgraded the company’s telephone system to a Voice over Internet Protocol (“VoIP”) platform and gave team members access to advanced features like wideband (HD) audio, desk phone control with ‘click to call,' extension mobility, as well as video calls and soft phone that help them perform their work more efficiently and effectively.

- 2021 – Advanced Metering Infrastructure ("AMI") Initiative/Meter Data Management ($242.4 million including AFUDC). This project enables us to provide more efficient and reliable service to our customers (*i.e.*, shorter outage response times and durations) and additional features and functions to our customers (*e.g.*, remote connect and disconnect). Ms. Cosby and Mr. Haines provide additional information about the benefits of the AMI program in their direct testimonies.

- 2021 – Advanced Distribution Management System ($24.3 million). This project includes an IT platform that will provide multiple next generation distribution grid functions and features, such as include fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation through voltage reduction; peak demand management; and support for microgrids and electric vehicles, that will benefit our customers. Mr. Haines provides more detail on this project in his direct testimony.

- 2021 – Interactive Voice Response/Contact Center Management ($8.0 million). This project installs the core IT functions that will enable multiple next generation call center capabilities such as intuitive natural language understanding interactive voice response, new agent desktop experience bringing context aware knowledge management articles, customer virtual assistant, improved workforce management and quality monitoring tools, enhanced virtual hold technology and operational analytics to help meet the increasing expectations of our customers. Ms. Cosby provides additional information about this new project in her direct testimony.

2022 PROJECTED IT CAPITAL BUDGET

Q. What process does the company use to identify the projects the IT department will implement?

A. Team members in our IT department collaborate with team members in Energy Supply, Electric Delivery, Customer Experience, and the gas company affiliates, and other smaller Tampa Electric departments to develop and maintain technology plans that align with the company's future needs. The technology plans reflect the projects needed in the functional areas and form the basis for the IT department's long-term plans and annual capital expenditure budgets.

Q. Once IT projects are approved, what steps does the company take to ensure that projects are "procured" at the lowest reasonable cost?

A. The IT department follows the formal bidding process for the purchase of all ordinary goods and services as outlined in company policies. The company's Procurement department conducts the bidding process so the company procures goods and services through an unbiased, consistent, and objective procurement process, that leads to the lowest reasonable cost. The key elements of the process are requesting formal and well-documented bids from three or more vendors, a full review of bidders' qualifications and information submitted, evaluating other factors such as diversity considerations, and ensuring proper level of approvals after a vendor is selected.

Q. What capital projects are included in the company's $27.5 million IT capital budget for the 2022 test year?

A. The projects reflected in our 2022 capital budget are needed to ensure compliance with regulations, promote cybersecurity, strengthen privacy protections, and enhance the experience we provide to our customers. The goods and services needed for the projects in the company's 2022 capital budget will be procured as described above and are needed and prudent. They include the following projects.

Cybersecurity. We will spend $2.3 million for new and upgraded tools that will strengthen the company's cybersecurity protections and keep pace with the ever-increasing capabilities of bad actors. The company's cybersecurity program ensures the confidentiality, integrity, and availability of customer information and company services.

Cybersecurity Compliance. We will spend $4.5 million on improvements to cybersecurity programs that are mandated or required by regulations and internal compliance standards.

Digitalization. We will spend $1.7 million for digitalization to provide new and innovative customer-facing services in the areas of mobility and data analytics and improve the efficiency of internal business functions through the application of artificial intelligence and machine learning solutions.

<u>Sustaining Investments for Applications.</u> We will spend $9.6 million to replace or update existing applications that soon will not be supported by vendors and update applications so they will provide new functions and features. Approximately $8 million of this investment is the IT department's share of the cost of upgrading the CRB system, which will improve the customer experience. This project is described in greater detail in Ms. Cosby's direct testimony.

<u>Sustaining Investments in Computing.</u> We will spend $1.6 million to upgrade end-of-life server hardware and pay for new team member computers, as needed.

<u>Sustaining Investments in Storage.</u> We will spend $2.3 million to ensure that the company has sufficient data storage to meet its growing needs. This level of capital spending also will ensure that the company has sufficient backup capacity to mitigate data loss scenarios.

<u>Sustaining Investments in Networks.</u> We will spend $1.9 million to replace computer network equipment that is no longer supported by the vendor and to provide more network capacity to support the increased demands of technology used by the business, such as data analytics.

Sustaining Investment in Telecom. We will spend $3.6 million to replace end-of-life equipment, to increase the capabilities of our telecommunications system, and to replace a single radio tower that is over 40 years old. The company needs to increase the capabilities of its telecommunications system to support the increased demands of technology used by the business such as smart grid field devices. Replacing the radio tower will reduce maintenance costs and provide additional space for antenna mountings.

2022 IT O&M EXPENSE BUDGET

Q. What amount of O&M expense for IT did the company include in the 2022 test year and what major activities are reflected in that expense amount?

A. The Tampa Electric O&M expense for IT in 2022 is $30.5 million. Direct labor costs account for approximately 60 percent of IT O&M expense. Outside services, which includes contractors, application management services, cloud application services, and application and hardware maintenance, accounts for approximately 30 percent of total O&M expense. The remaining 10 percent is composed of other items such as rent or lease expense.

Q. How does the 2022 test year IT O&M expense amount compare to IT O&M expenses in the company's 2013 rate case.

A. The 2022 test year IT O&M expenses are higher than in the company's 2013 rate case for understandable reasons. As technology solutions have evolved, Tampa Electric's computing environment has changed from a largely centralized mainframe computer for its core business applications to a distributed computing environment. The new systems the company uses for its core business applications and its operational systems are data-intensive, highly resilient, and provide significant new capabilities and insight for our customers and business operations. The architecture of these newer distributed systems is more complex and requires multiple interconnected computers to operate properly. Consequently, there are higher hardware and software costs associated with the newer distributed systems. Additionally, some of the systems utilize software and hardware systems located in the cloud, not on Tampa Electric's premises, which are considered O&M expenses rather than capital costs. The higher numbers reflected in the 2022 test year are representative of these technology changes.

More specifically, 2022 represents an increase of approximately $12.75 million or 72 percent over the 2013 spending level of approximately $17.75 million. Labor costs increased by $7.6 million with the major driver being the headcount increase for cybersecurity, IT operations monitoring capability increases, and creating a center of excellence to support the distributed systems associated with CRB. The other major driver of the increase is maintenance costs associated with the implementation of multiple technology projects, which increased by $2.8 million.

While the incremental increases in technology spend in the period between 2013 and 2022 were all individually justified through internal company procedures, the reasonableness of overall spend on IT can only be justified using external benchmarking. To this end, TEC benchmarks on a variety of IT measures, including cost, against a group of investor-owned utilities. Based upon a 2020 study of 2019 actuals, IT capital and O&M spending per customer account served (Tampa Electric and Peoples Gas System) was the 7th lowest out of 21 companies reporting. IT capital and O&M spending per member of the workforce (Tampa Electric and Peoples Gas System) was the 7th lowest out of 22 companies. Based upon these two metrics, 2019 IT costs are in the 2nd quartile of lowest cost per unit. The net benefit to the company’s overall O&M expense from technology advancements is also reflected in our total O&M falling below the Commission’s O&M benchmark, as described in the direct testimony of Tampa Electric witness Jeffrey S. Chronister.

SUMMARY

Q. Please summarize your direct testimony.

A. Tampa Electric’s IT department provides technology and services that support all aspects of the company’s operations. The amounts the company spent for IT projects since 2013 and plans to spend in 2021 and 2022 are reasonable and prudent. We made these investments to support safety, a greener fleet, and an improved customer experience. The company’s 2022 test year capital and O&M budgets are reasonable and prudent, will enhance cybersecurity protection, promote operating efficiency, enable useful features and functions, and improve the experience we provide to our customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of David A. Pickles was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

DAVID A. PICKLES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID A. PICKLES

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

A. My name is David A. Pickles. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or the "company") as Vice President of Energy Supply and Electric Delivery/Energy Supply Asset Management.

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

A. I am responsible for ensuring the safe and reliable operation of all the generating assets at Tampa Electric, including solar operations. This includes oversight of all safety, environment, compliance, team member, operating, and capital budget management decisions in our Energy Supply department. I am also responsible for the Asset Management decisions for both Electric Delivery and Energy Supply. My focus is on ensuring overall system reliability through proper maintenance and investment strategies over the life cycle of all assets. I am responsible for fuel procurement, along with purchase power agreements. My responsibilities include electric system and resource planning in support of long-term system reliability, and I am also responsible for general procurement and contract activities for Tampa Electric.

Q. Please provide a brief outline of your educational background and business experience.

A. I am a Chemical Engineer and a graduate of Dalhousie University based in Halifax, Nova Scotia, Canada. I am a registered Professional Engineer in the Province of Nova Scotia.

I joined Nova Scotia Power in 2001 as a Plant Engineer and held many roles over the next 15 years including Maintenance Manager, Plant Manager, Senior Plant Manager, Director, and Senior Director of Operations. In 2016, I became the Vice President of Operations for Emera Energy and was responsible for 1,100 MW of generating capacity in three American states and two Canadian provinces.

I joined Tampa Electric in 2018 and assumed responsibility over Big Bend Generating Station and Energy Supply's

Engineering and Project Management group. Most recently, I have served as Vice President of Energy Supply and Electric Delivery/Energy Supply Asset Management.

Q. Have you previously testified before the Florida Public Service ("Commission") or other regulatory authority?

A. Yes. I have testified or filed testimony before the Nova Scotia Utility and Review Board in 2014 and 2015 in support of the Annual Capital Expenditure Plan; Application by Nova Scotia Power Inc. ("NSPI") for Approval of its Annual Capital Expenditure Plan for 2014 (M05998) and Application by NSPI for Approval of its Annual Capital Expenditure Plan for 2015 (M06514).

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to (1) provide an overview of the company's Energy Supply system and how it has transformed over the years; (2) outline the company's future plans for Energy Supply; (3) demonstrate that the company's production plant construction program, capital budgets, and resulting energy supply rate base amounts for 2022 are reasonable and prudent; and (4) show that the company's proposed level of operations and maintenance expense ("O&M") for energy supply in the 2022 test year is reasonable and prudent.

Q. How does your direct testimony relate to the direct testimony of other Tampa Electric witnesses?

A. My direct testimony addresses the company's overall electric generating system and explains how the Big Bend Modernization Project ("Big Bend Modernization"), early retirement of Big Bend Unit 3, and the addition of 600 MW_{ac} of utility scale solar generating capacity ("Future Solar") fit into Tampa Electric's overall plans. These projects are major components of our goal to make the company safer, cleaner, greener, and to improve the customer experience.

Tampa Electric witness J. Brent Caldwell will explain the details of the company's decision to invest in Big Bend Modernization, its phased approach to transforming the Big Bend Station, and why the project is prudent and in the best interests of our customers. He will also explain why retiring Big Bend Unit 3 in 2023, rather than its previously planned retirement date of 2041, is prudent and in the best interests of our customers.

Tampa Electric witness Davicel Avellan will explain how the changes underway at Big Bend Station will impact our depreciation and dismantlement rates and describe our need to recover the undepreciated net book value ("NBV") of the portions of Big Bend Units 1, 2, and 3 to be retired and obsolete inventory via capital recovery schedules.

Tampa Electric witness C. David Sweat will explain the details and projected costs of Tampa Electric's plans for Future Solar and how our phased approach for adding this cost-effective generation to our portfolio maximizes the available economies of scale and leverages lessons-learned from our SoBRA experience.

Tampa Electric witness Jose A. Aponte will demonstrate that each of the 11 planned Future Solar projects is cost-effective, prudent, and in the best interests of our customers.

Finally, Tampa Electric witness John C. Heisey will support our request to include fuel inventory in the company's working capital allowance. He will also explain how the changes we are making to the dispatch of coal-fired generation necessitate a modification to the traditional 98-day average burn inventory target for solid fuel.

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

A. Yes. Exhibit No. DAP-1, entitled "Exhibit of David A. Pickles" was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. My exhibit consists of 14 documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by David A. Pickles
Document No. 2	Thermal Efficiency (2013-2020)
Document No. 3	Emissions (2013-2020)
Document No. 4	System Equivalent Availability Factor ("EAF") (2013-2020)
Document No. 5	Environmental Regulations for Coal Fired Generation
Document No. 6	Summary of Big Bend Modernization Project and Costs by Phase
Document No. 7	Big Bend Unit 1 Retirement Assets
Document No. 8	Big Bend Unit 2 Retirement Assets
Document No. 9	Big Bend Unit 1 and 2 Obsolete Inventory

Document No. 10	Big Bend Unit 3 Retirement Assets
Document No. 11	Energy Supply Rate Base Growth (2013-2022)
Document No. 12	Energy Supply Capital Additions (2022-2023)
Document No. 13	Energy Supply O&M Expenses (2013-2022)
Document No. 14	2022 Energy Supply O&M Benchmark

Q. Are you sponsoring any sections of Tampa Electric's Minimum Filing Requirement ("MFR") Schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR schedules listed in Document No. 1 of my exhibit. The data and information on these schedules were taken from the business records of the company and are true and correct to the best of my information and belief.

ENERGY SUPPLY OVERVIEW AND TRANSFORMATION

Q. Please describe the company's Energy Supply and Asset Management Department.

A. Our Energy Supply and Asset Management Department ("Energy Supply") has a combined staff of approximately 545 team members. Energy Supply combines all the necessary resources to support the company's thermal and solar generating operations; environmental management; engineering and project management; resource planning; system planning; natural gas and solid fuel procurement; energy trading; asset and capital management (for both Energy Supply and Electric Delivery); along with regulatory compliance (North American Electric Reliability Corporation ("NERC")/Federal Energy Regulatory Commission ("FERC")); procurement; and facility services.

Q. What role does safety play in Energy Supply?

A. Safety is our number one consideration. We are committed to the beliefs that all injuries are preventable and that no business interest can take priority over safety. We believe that safety is everyone's responsibility and that all our team members must be personally engaged in all aspects of safety.

The foundation of our safety program is a multi-tiered Safety Management System that sets minimum expectations for safety leadership; addresses risk management; prescribes programs, procedures, and practices; promotes safety communication, awareness, and training; cultivates a strong safety culture and safe behavior; sets contractor safety management standards; enhances asset integrity; establishes tools for measuring and reporting; prescribes incident management and investigation procedures; and includes auditing and compliance measures.

I am proud to report that the Occupational Safety and Health Administration ("OSHA") Recordable Injury rates in Energy Supply have improved since 2017 and that we had zero recordable injuries in 2018 with millions of exposure hours worked. I am pleased with the progress we have made and recognize that creating a safe work environment requires constant attention and a relentless pursuit of safety excellence.

The level of employee engagement in safety continues to improve overall safety performance across the entire organization. This was never more evident than our safety results in 2020. Our safety performance in 2020 was one of our best ever.

- Best incident rate with respect to recordable injuries.
- 1 million safe work hours without a recordable injury.
- 2 million work hours without a lost time injury.
- Lowest controllable vehicle incident rate with 12 accidents.

- Safely drove 1 million miles.

Q. What is Asset Management and how has the company integrated Asset Management techniques into its planning and operations?

A. Asset Management is a disciplined way of thinking and managing that aligns engineering, operations, maintenance, other technical and financial decisions, and processes for the purpose of optimizing the value of our assets throughout their lifecycles.

Tampa Electric strives to achieve its asset reliability goals by focusing on the following three Asset Management objectives.

The first objective is the integration of asset monitoring, health and risk assessment, work planning and scheduling, capital planning, outage planning, risk management, and other supporting asset management processes into continuous business processes.

The second objective is the broader engagement of team members and subject matter experts in these continuous processes, the establishment of asset management responsibilities throughout the organization, and ensuring team members are empowered with industry best practice through awareness and training.

Finally, we sustain the integrated processes and engagement of our teams through documentation and standardization of technical and business processes and the implementation of supporting operational and information technology systems.

We implement these Asset Management concepts in our short term (weekly planning and scheduling) and long term (outage planning) work management cycles.

Applying Asset Management principles gives us a comprehensive understanding of the condition of our assets and the risks associated with them and allows us to better identify and prioritize the work that needs to be done. This level of understanding enables us to improve our planning and scheduling of work, lowers the costs and risks of operating our system, and improves efficiency and reliability – all of which promote a positive customer experience.

Q. Please generally describe the company's current electric generating system.

A. Tampa Electric maintains a diverse portfolio of electric generating facilities to safely provide reliable, cost-effective electric power for its customers in an environmentally sensitive manner. Our generating portfolio consists of 15 generating units and five peaking units at three central generating stations, and 13 geographically dispersed solar sites, for a total of approximately 5,790 MW of winter peaking capacity. Our electric generating units include dual fuel (solid fuel/natural gas) steam units, combined cycle units ("CC"), combustion turbine ("CT") peaking units, an integrated gasification combined cycle ("IGCC") unit, and photovoltaic solar facilities ("Solar").

Q. Please describe the company's three central electric generating stations.

A. The company's three central electric generating stations are the Big Bend Power Station ("Big Bend"), the Polk Power Station ("Polk"), and the H.L. Culbreath Bayside Power Station ("Bayside").

Big Bend currently consists of Big Bend Units 2, 3, and 4, which are pulverized coal fired steam units. They are equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction ("SCR") air pollution control systems. We modified each of the Big Bend units since our last rate case in 2013 so that they also can be fired with natural gas, *i.e.*, added dual-fuel capability.

Big Bend Unit 1 is in the process of being modernized and is not operating, but the other three units are in service. Units 2 and 3 are currently burning natural gas only and are scheduled for retirement in November 2021 and April 2023, respectively. Big Bend Unit 4 can operate on coal or natural gas. Big Bend CT4 is a natural gas aero derivative CT.

Bayside consists of two natural gas fired combined cycle ("NGCC") units and four aero derivative CTs. Bayside Unit 1 consists of three CTs, three Heat Recovery Steam Generators ("HRSG") and one steam turbine. Bayside Unit 2 consists of four CTs, four HRSGs, and one steam turbine. Bayside Units 3, 4, 5, and 6 are the four natural gas aero derivative CTs.

Polk has two units. Polk Unit 1 is a dual fuel IGCC/natural gas unit consisting of one CT, one HRSG, and one steam turbine. Polk Unit 2 uses four natural gas CTs, four HRSGs, and one steam turbine. Two of the Polk 2 CTs can use distillate oil as a back-up fuel. The Polk Unit 2 CTs were transformed into highly efficient CC generating units ("Polk 2 Conversion") in accordance with the Stipulation and Settlement Agreement ("2013 Stipulation") that resolved our last rate case.

Q. Please describe the company's existing Solar facilities.

A. Tampa Electric currently owns and operates 655 MW_{ac} of solar generating capacity at 13 geographically dispersed locations throughout its service territory. Our solar portfolio includes 632.1 MW_{ac} of single axis tracking PV solar at 11 sites in Hillsborough and Polk Counties, a 1.6 MW_{ac} fixed tilt solar PV rooftop canopy array located at the south parking garage at Tampa International Airport, a 1.4 MW_{ac} fixed tilt solar PV ground canopy array located at Legoland Florida, and a 19.8 MW_{ac} single axis tracking solar station coupled with a 12.6 MW battery storage unit located at Big Bend. 600 MW_{ac} of this capacity was installed in cost-effective increments pursuant to the company's 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). All the company's solar assets have been placed into service since 2013.

Q. Please describe the mix of fuel the company currently uses to generate electricity and how it has changed since the company's last rate case in 2013.

A. The changes to our generating system have dramatically changed the mix of fuel we use to generate electricity.

We reduced our coal consumption in tons by approximately 90 percent since 2015.

In 2013, about 59 percent of Tampa Electric's electricity was generated using coal, about 41 percent was natural gas-fired, and we had no solar generation.

By 2020, about 5 percent of our electricity was generated using coal, about 89 percent was natural gas-fired, and approximately 6 percent was from solar, and less than 1 percent from light oil.

We have 470 MW of capacity that can use distillate oil as a backup fuel at Polk, but the amount of distillate oil used each year is *de minimis*.

Q. Have the changes described above improved the company's thermal efficiency and environmental profile?

A. Yes. We have reduced our average net system heat rate (Btu/kWh), which reflects the thermal efficiency of our generating fleet, from about 9,200 in 2013 to 7,599 in 2020, an improvement of about 17 percent. We reduced our carbon emissions from 15.7 million tons in 2013 to about 8.8 million tons in 2020. By 2023, we will have reduced our carbon dioxide emissions by the equivalent of removing one million cars from local roadways. Document Nos. 2 and 3, respectively, in my exhibit provide more details about how our thermal efficiency and emissions profile have improved since 2013.

Q. Have these changes to the company's generating facilities helped reduce the company's annual fuel expenses?

A. Yes. Our annual fuel expenses, which are a direct pass-through to our customers, have declined by about 40 percent from a peak of over $700.0 million in 2014 to approximately $425.0 million in 2020. Year over year fuel variances from (2016-2020) can be found in MFR Schedule C-09. Some of this reduction is attributable to lower commodity prices, but we delivered the value of lower fuel prices to customers through prudent construction of solar generation, expansion of dual-fuel capability at our power plants, continued investments in efficient natural gas fired combines cycle technology, and careful dispatching of our generating units. By December 31, 2020, the Polk and SoBRA projects saved our customers over $184.0 million in fuel costs since 2013.

Q. Please describe the reliability of Tampa Electric's generating units since 2013.

A. The reliability of our generating fleet is measured by generating unit annual net EAF, which calculates the amount of time a unit is expected to be in service after accounting for planned and unplanned outages.

Our overall fleet EAF has improved from approximately 77 to 84 percent since 2013. Our fleetwide EAF is a weighted average of performance, with the NGCC fleet having a very high EAF (high 80s to low 90s) and the coal fleet operating in the low 70s. The lower EAF across the coal fleet is a result of higher wear and tear caused by coal combustion, corresponding longer duration planned maintenance outages, and the most recent major outage on Big Bend Unit 4.

Document No. 4 of my exhibit provides additional details on our system EAF since 2013.

Q. Have generation changes since 2013 enabled the company to make other operational changes?

A. Yes. The changes described above, together with changes in the natural gas market, have substantially changed how our generating fleet is dispatched and the level of O&M expenses required to sustain reliable operation. They have also enabled us to make significant staffing reductions at Big Bend through natural attrition. We are projecting further staffing reductions and expense savings as we implement Big Bend Modernization and retire Big Bend Unit 3. These O&M savings are reflected in the 2022 budget and O&M expense projections in 2023 and beyond.

Although the number of team members at Big Bend is declining, the number of people working in our Solar operations department is growing. This growth is being driven by the construction and operation of our Future Solar projects and by a transition of current Solar O&M responsibilities from external third-party support to in-house resources. This transition will help us to continue delivering cost competitive generation options and develop in-house Solar skills and knowledge.

Q. Are the changes described above the beginning of the transformation of the company's generating fleet?

A. No. The changes to our generating system described above, Big Bend Modernization and our Future Solar, are best understood as part of the company's long history of generation innovation and transformation to meet the needs of the times. Tampa Electric has adapted its generating portfolio to capture technological improvements and fuel price savings, in response to changing public policy concerns, and to embrace the evolving expectations of our customers.

Q. Please explain further.

A. During most of the 20th century, Tampa Electric relied on oil fired generation to serve its customers. Oil provided safe, reliable, and relatively inexpensive generation. A large portion of the oil used by Tampa Electric was imported to the United States from the Middle East under the supervision of the Organization of Petroleum Exporting Countries ("OPEC").

In the early 1970s, OPEC stopped selling oil to the United States. This oil embargo sent gas prices through the roof, and oil prices quadrupled.

Federal and state policy makers responded by promoting energy conservation and encouraging utilities to focus on coal, which at the time was plentiful in the United States and cheaper than oil as a generating fuel.

For example, the Commission adopted the oil backout cost recovery factor rule, Rule 25-17.16, Florida Administrative Code, in 1982 ("Oil Backout Rule") to allow Florida utilities to recover the cost of implementing supply side conservation projects whose primary purpose was the economic displacement of oil generated electricity.

Q. Did Tampa Electric respond to these economic and public policy changes?

A. Yes. First, the company converted its then oil-fired Gannon Units 1 through 4 to burn coal in the 1980s and recovered the costs of the conversion via the Oil Backout Rule.

Second, the company built Big Bend Units 1 through 4 in the 1970s and 1980s when the economy, reliability, and efficiency of coal and public policy considerations made doing so in the public interest.

Third, in 1996, the Tampa Electric Polk Unit 1 project came on-line with the assistance of a generous grant from the Department of Energy to test coal gasification, which was an innovative, more environmentally friendly alternative to traditional coal fired generation. This government sponsored project provided Tampa Electric significant power generation without the environmental consequences from the normal combustion of coal.

Fourth, the company retired its Hookers Point Power Station in 2003. Hookers Point was placed into service in the 1950s and consisted of five heavy oil conventional boiler and steam turbine units.

Q. Has the public policy in favor of coal and economics of coal-fired generation changed?

A. Yes. Concerns about the environment led to significant federal and state regulatory actions that forced utilities like Tampa Electric to install pollution control equipment to limit the emissions and other environmental impacts from coal-fired generation. The company added pollution control equipment at Big Bend in the 1990s and 2000s as required by legislative responses to growing concerns about the environment. The environmental regulations that affected coal-fired generation and how Tampa Electric complied with them are summarized in Document No. 5 of my exhibit.

The environmental compliance costs associated with burning coal have made generating electricity with natural gas an economically attractive alternative to coal. Improvements in CC generating technology, the recent improvements in hydraulic fracking technology, and the resulting abundant domestic sources of natural gas have further improved the relative economics and environmental value of natural gas and propelled the movement away from coal as a generating fuel.

Q. Has Tampa Electric responded to these changes?

A. Yes. Tampa Electric responded to these changes in 2002 and 2003 by converting its then coal-fired Gannon Station Units 5 and 6 to natural gas-fired Bayside Units 1 and 2. The company later added four natural gas-powered aero derivative units at Bayside and one natural gas-powered aero derivative unit at Big Bend. The Polk 2 Conversion and adding dual-fuel capability at Big Bend were also a response to the changing economics and public policy views of natural gas fired generation relative to coal.

Q. Were all the changes to the company's generating fleet described above prudent?

A. Yes. Each change was made considering the conditions and circumstances known at the time after careful internal studies that considered safety, reliability, economics, and then-existing environmental considerations. All were the subject of regulatory and intervenor scrutiny.

CURRENT AND FUTURE ENERGY SUPPLY PLANS

Q. Are technological improvements, fuel prices, and public policy considerations continuing to drive changes in how the company generates electricity?

A. Yes. Growing concern about our environment and global warming continue to increase and inform the actions of policy makers. Technology improvements have made solar generation a cost-effective alternative to natural gas-fired generation within the operating parameters of a utility's system. Battery storage technology continues to improve and is expected to make battery storage an important part of the electric grid, while further reducing our need to burn fossil fuels to generate electricity.

Absent an unforeseen change, the future of coal as a fuel for generating electricity appears to be ending, and the future is bright for renewable energy resources and batteries. In the meantime, however, we still depend on highly efficient NGCC technology to meet a large portion of our electric generation needs.

Q. How has Tampa Electric responded to these recent changes in favor of renewable energy?

A. First, beginning in 2014, Tampa Electric added relatively small solar projects to its electric system at the Tampa Airport, Legoland, and Big Bend. These projects include a 1.6 MW_{ac} fixed tilt solar PV rooftop canopy array located at the south parking garage at Tampa International Airport, a 1.4 MW_{ac} fixed tilt solar PV ground canopy array located at Legoland Florida, and a 19.8 MW_{ac} single axis tracking solar facility at Big Bend. These projects were prudent as an important part of the company's effort to become familiar with solar technology and how solar operates on its system.

Second, from 2017 to 2020, the company constructed 600 MW_{ac} of solar capacity pursuant to its 2017 Agreement. Together with its initial small solar projects, these cost-effective solar additions have allowed the company to power the equivalent of more than 100,000 homes, businesses, and schools. The prudence of these projects was determined as part of the 2017 Agreement and the SoBRA proceedings that approved them.

Third, the company has installed a 12.6 MW battery storage unit at Big Bend and coupled it with the single axis tracking solar facility there. This battery storage pilot is prudent as an effort by the company to learn how battery storage interacts with generation resources and how to best integrate them into our electric grid.

Fourth, the company is planning Future Solar in three phases from 2021 to 2023 as discussed further in the testimonies of Mr. Sweat and Mr. Aponte.

And finally, the company's Big Bend Modernization is well underway and will convert part of Big Bend into state-of-the-art, highly efficient NGCC generation.

A. <u>BIG BEND MODERNIZATION PROJECT</u>

Q. Please describe the Big Bend Modernization Project.

A. As part of Big Bend Modernization, the company will retire Big Bend Unit 2 and repower Big Bend Unit 1 as a clean natural gas-fired two-on-one CC generating facility. Big Bend Unit 1 will be repowered with a new NGCC unit that will use the unit's existing steam turbine generator, and once-through cooling system. Big Bend Unit 1 will have a nominal net generating capacity of 1,090 MW when the repowering is complete. The analysis that led to the decision to proceed with the project and why the project is prudent are described in the direct testimony of Mr. Caldwell.

Q. What are your responsibilities for Big Bend Modernization?

A. I am responsible for ensuring that Commissioning support and start-up activities are coordinated with plant operating, maintenance, engineering staff and to ensure we have a fully trained team ready to support commercial operation upon project completion.

Big Bend Modernization will be constructed in two phases. The first phase will result in the operation of the two new highly efficient CTs in simple cycle mode, is expected to cost $409.4 million, and will be complete in December 2021. The second phase consists of the addition of the HRSG and will result in the unit's operation in CC mode, is expected to cost $495.2 million, and will be in service in December 2022. The total cost of the project is expected to be $904.6 million. Document No. 6 of my exhibit reflects a summary of Big Bend Modernization and costs by phase.

Q. What portions of Big Bend Modernization are complete?

A. The completed elements of the project and dates they were completed are:

Conceptual Engineering	May 2017
Preliminary Design and Engineering	January 2018
File Site Certification and Permit Applications	April 2018
Award Contracts	June 2019
Permits Received	July 2019
Big Bend Unit 1 Shutdown	June 2020

Q. Which elements of Big Bend Modernization remain to be completed?

A. The remaining project milestones are listed below, along with their estimated completion dates.

Simple Cycle First Fire	August 2021
Combustion Turbines in Service	December 2021
Big Bend Unit 2 Shutdown	December 2021
Combined Cycle Unit in Service	December 2022

Q. What portions of Big Bend Units 1 and 2 will be reused and which portions will be retired?

A. Some, but not all the component parts of Big Bend Unit 1 will be refurbished and re-used for the repowered Unit 1. Substantially all Big Bend Unit 2 will be retired as well as some plant equipment that is common to the two units.

The Big Bend Unit 1 assets to be retired had an undepreciated NBV of $122.9 million as of December 31, 2021, which amount will not be recovered by the time of retirement through the normal depreciation process. These assets generally include the existing boiler and most of the pollution control equipment and are listed in more detail in Document No. 7 of my exhibit.

The Big Bend Unit 2 assets to be retired had an undepreciated NBV of $171.3 million as of December 31, 2021, which amount will not be recovered by the time of retirement through the normal depreciation process. These assets include substantially all the property units associated with Big Bend Unit 2. The Big Bend Unit 2 assets to be retired in conjunction with the project are summarized in Document No. 8 of my exhibit.

Q. Are there items of inventory associated with the portions of Big Bend Units 1 and 2 to be retired as part of the project that will no longer be used and useful to provide electric service?

A. Yes. The dollar value of the obsolete inventory associated with the Big Bend Unit 1 Retirement Assets was approximately $1.0 million as of December 31, 2019, and includes all parts associated specifically for Unit 1. This inventory cannot be used in any of the company's other generating stations, has no salvage value, and will no longer be used or useful for the generation of electricity at Big Bend or otherwise.

The dollar value of the obsolete common inventory that could be utilized interchangeably for both Big Bend Unit 1 and Big Bend Unit 2 was approximately $4.1 million as of December 31, 2019 and includes all replacement parts associated with the Big Bend Units 1 and 2. This inventory cannot be used in any of the company's other generating stations, has no salvage value, and will no longer be used or useful for the generation of electricity at Big Bend or otherwise.

A schedule showing these items of obsolete inventory is included as Document No. 9 of my exhibit.

Q. What amounts of construction work in progress and electric plant in service are associated with Big Bend Modernization in the 2022 test year?

A. Phase One went in-service prior to the 2022 Test Year, thus there is $0 in Construction Work in Progress ("CWIP") and $383.9 million of Plant In-Service.

Phase Two goes in-service December 2022 during the 2022 Test Year, there is $0 in CWIP as this phase is earning Allowance for Funds Used During Construction ("AFUDC") and is Florida Public Service Commission ("FPSC") Adjusted out of CWIP in rate base (See Segregation of CWIP / Surveillance) and $34.3 million of Plant In-service (1/13 of the December 2022 addition amount of $445.7 million.

Q. What amounts of construction work in progress and electric plant in service are associated with Big Bend Modernization in calendar year 2023?

A. Phase One will go in-service prior to the 2022 Test Year, thus there is $0 in CWIP and $384.1 million of Plant In-Service. Phase Two goes in-service December 2022 during the 2022 Test Year, thus there is $0 in CWIP and $454.7 million of Plant In-Service in 2023.

Q. Please describe the procurement practices Tampa Electric used for Big Bend Modernization.

A. The company followed its well-established, formal bidding processes and procedures to procure all material, major equipment, and services for the project. These procurement activities were performed by the company's Procurement Department to ensure and maintain an unbiased, consistent, and objective procurement process. Key elements of the process included: requesting formal and well documented bids from three or more vendors, a full review of bidder qualifications, and a thorough review of their cost proposals. The company selected the best evaluated vendor based on these criteria to ensure the lowest reasonable cost for our company and our customers.

Q. Will Big Bend Modernization be completed as scheduled?

A. Yes. The CTs are expected to be in-service in December

2021, and the complete CC cycle unit schedule is on target and expected to be in service in December 2022.

Q. Will the Big Bend Modernization be completed within budget?

A. Yes. The project costs are within budget. Through February 2021, approximately 65 percent of costs have been incurred, and all major material and installation contracts have been awarded.

Q. Is Big Bend Modernization prudent and in the best interests of the company's customers?

A. Yes. The project costs are prudent and reasonable, and the project will go in service on time and within budget. The project is cost-effective and is a prudent investment to serve Tampa Electric's customers with lower fuel usage and less emissions. The testimony of Mr. Caldwell discusses the project's cost-effectiveness, as well as the savings and other benefits it will provide to customers.

B. EARLY RETIREMENT OF BIG BEND UNIT 3

Q. What are the company's plans for Big Bend Unit 3?

A. Big Bend Unit 3 is a pulverized coal-fired steam unit. It was placed in service in May 1976. It has a name-plate capacity of 445.5 MW and has summer and winter capability of 395 MW and 400 MW, respectively. The expected retirement date reflected in the company’s previous depreciation study is 2041. The company has concluded that it is prudent and in the best interests of our customers to retire Unit 3 in April 2023.

Q. Why does the company plan to retire Unit 3 in 2023?

A. We accelerated the retirement of Unit 3 from 2041 because it will save customers money by, among other things, avoiding a very expensive, time consuming, and operationally challenging major outage that will be needed if Unit 3 is to continue operating beyond 2023. We estimate that the early retirement of Unit 3 will avoid total expenditures of $491.1 million ($298.0 million Net Present Value). It will also help make the company cleaner and greener. A full explanation of the reasons why the early retirement of Unit 3 is prudent is included in the testimony of Mr. Caldwell.

Q. Is April 2023 the right time to retire Unit 3?

A. Yes. Big Bend Modernization is expected be complete and in service in December 2022. Retiring Unit 3 as soon as practical after this date provides contingency in the event of unexpected Big Bend Modernization delays, it also keeps Unit 3 operational if needed to support manatee protection during the winter of 2022 through 2023 and allows Unit 3 to retire soon enough to avoid the major outage described above. Unit 3 will remain in service and be used and useful in the provision of electric service during the 2022 test year.

Q. What Big Bend Unit 3 assets will be retired?

A. The Unit 3 assets to be retired in April 2023 had an undepreciated NBV of $187.4 million as of December 31, 2021, which amount will not be recovered by the time of retirement through the normal depreciation process. These assets include substantially all the property units associated with Big Bend Unit 3. The Big Bend Unit 3 assets to be retired in April 2023 are listed in more detail, with their corresponding projected NBV as of December 31, 2021, in Document No. 10 of my exhibit.

C. OVERALL ENERGY SUPPLY PLANS

Q. How do the Future Solar projects, Big Bend Modernization, and early retirement of Big Bend Unit 3 fit into the company's overall generation plan?

A. Tampa Electric is on a journey to world class safety, improved environmental performance, and excellent customer experience. We will accomplish our safety goals through team member engagement, training, and a focus on safety 24 hours a day and seven days a week. We will accomplish our environmental goals through reduced carbon emissions, reduced coal combustion, and a transition to renewables.

The customer experience will improve through a focus on improving the overall reliability of our energy supply system by diversifying our generation portfolio through the introduction of renewable solar generation and seeking opportunities for increased distributed generation.

The Future Solar described by Mr. Sweat and Mr. Aponte are shown on MFR Schedule B-11 and are cost-effective additions that will enhance our fuel diversity and, because the cost of fuel for Solar is zero, will promote price stability for our customers. Solar, together with distributed generation and battery technology, will combine with our traditional centralized generating stations to provide a reliable and more efficient generation portfolio.

Big Bend Modernization additions are shown in MFR Schedule B-11 and will improve the company’s overall system efficiency and generating system reliability; will make the Big Bend generating units more reliable on a stand-alone basis; and will enable the company to burn less coal, use less water, and generate less wastewater than under the status quo, making Tampa Electric cleaner and greener. The project will lower the emission of CO_2, SO_2, and NO_x relative to current projected levels. It also will enable the company to moderate the amount of money it must spend on solid fuel before the project is complete and to maintain an acceptable level of warm water discharge to the existing manatee sanctuary. It will complement the company’s existing and planned solar projects by providing winter reserve margin, 24-7 energy, and regulation support for solar generation, which is an intermittent resource.

The flexibility and “following” ability inherent in the repowered Big Bend Unit 1 will effectively complement the company’s utility scale solar. The repowered Big Bend Unit 1 will be able to quickly offset the variability of the solar plants by ramping up or reducing output. These reliability attributes produce fuel savings for customers by allowing solar to fully dispatch first where the NGCC plants can follow the solar output and curtailment. This ensures customers will receive a reliability benefit when solar wanes and fuel cost savings when solar is producing.

These major investments in NGCC technology and Solar will have an immediate and lasting positive effect through carbon reductions, increased reliability, reduced O&M expense, and headcount reductions.

Our investments in NGCC and Solar will require fewer worker hours to operate and maintain and are already allowing us to reduce team member headcount by managing attrition rates, reducing our use of contractors, and reassigning team members to jobs that add value to the transformed plant. These technologies also require fewer financial resources to operate and allow the company to retire solid fuel assets that cost more to operate and maintain. Indeed, the early retirement of Big Bend Unit 3 will significantly reduce the company's carbon emissions and reduce its future environmental compliance risks.

Through these NGCC and Solar investments and the retirement of solid fuel assets, the company will maintain a diversified fuel portfolio and continue to develop fuel supply redundancies.

D. OTHER FUTURE ENERGY SUPPLY PLANS

Q. Does the company have generation plans beyond the 2022 test year?

A. Yes. In addition to Big Bend Modernization and Future Solar, which will go into service at different times in 2022 and 2023, the company's plans include a streamlined approach to meeting winter peaks with capacity enhancements at Bayside and the addition of distributed resources such as reciprocating engines and additional battery storage to be deployed in 50 to 60 MW increments.

We expect the combination of reciprocating engines and battery storage to deliver flexible, quick response peaking capacity. They will work in concert to provide cost savings, operational flexibility, environmental and reliability benefits for customers, and value through improved efficiency and system reliability. Our plans reflect an agile deployment of resources that will match the timing and capacity increments needed to satisfy the company's future reserve margin requirements.

Q. Is the company planning any innovative Energy Supply projects?

A. Yes. Tampa Electric has several innovative projects that will advance the company's understanding of symbiotic relationships available through Solar. These include an Agrivoltaics project and a Floating Solar project.

Agrivoltaics is a new way of combining renewable energy with agriculture by positioning plants or crops between elevated solar panels. This method may enable dual land use that will benefit the farming industry; help fulfill federal, state, and local government goals for supporting agribusiness; and increase farmable acreage as solar development continues. We have selected a seven-acre site at Big Bend for a demonstration project where approximately four acres will be farmed under a solar canopy that will be designed to produce 1.1 MWac.

We will also install a floating solar project in one of Big Bend's retention ponds. This project will test a beneficial use of retention ponds or other similar infrastructure and will produce 1 MWac of Solar energy. The company hopes to demonstrate that floating solar will reduce evaporation, conserve water, lower the installation and maintenance costs relative to other solar facilities, reduce exposure to wind events, and decrease algae growth in the pond.

2022 ENERGY SUPPLY RATE BASE

Q. How does the amount of production plant for the 2022 test year compare to the amount of production plant in the company's 2013 rate case?

A. The production plant has increased by $1.743 billion since 2013. It is projected to be $5.642 billion in 2022 versus $3.899 billion in 2013.

Q. What major projects since 2013 are reflected in this increase?

A. Approximately $545.3 million of this increase is attributable to the Polk 2 conversion approved and deemed prudent in the 2013 Stipulation and described above.

Another $865.7 million of this increase is attributable to the construction of the company's first 600 MWac of solar generation capacity that was authorized and deemed prudent in the 2017 Agreement and associated SoBRA proceedings. Approximately $411.8 million of the increase is attributable to the Big Bend Modernization, and $346.5 million is associated with Tranche One of Future Solar.

The remainder of the increase is attributable to prudently incurred annual sustaining capital expenditures required to maintain the operational and environmental reliability of the company's existing generating fleet and so that those generating units will remain used and useful for delivery of electric service to our customers.

In 2018, the company performed a major planned outage for Bayside steam turbine Unit 2 at a cost of $17.2 million, along with the replacement of the Polk Unit 1 gas turbine rotor, at a cost of $14.7 million.

In 2019, the company performed a major planned outage for the Big Bend 3 steam turbine at a cost of $7.8 million, along with phase one of a planned two-phase major outage on Big Bend Unit 4 at a cost of $39.9 million.

In the spring of 2020, the company completed Phase Two of the Big Bend 4 major outage, which included a steam turbine major outage, precipitator field replacement, duct work replacement, and boiler waterwall tube replacements at a cost of $56.1 million.

In 2021, Bayside will start a multi-year (2021-2023) project, addressing all seven natural gas turbines that will significantly improve operational efficiency and flexibility, as well as increase the station's output by more than 128 MW. This project has a total projected cost of $76.0 million.

Document No. 11 of my exhibit shows how these projects combine to make up the increase in the Energy Supply (production plant) portion of the company's rate base from 2013 to 2022.

Q. Please describe the major production plant additions for 2020, 2021 and 2022 as shown on MFR Schedules B-7, B-8, B-11, and B-12.

A. For 2020, major production plant additions include $185.0 million for completion of the final phase of the company's first 600 MWac of solar generation capacity, and $71.8 million in additions related to the completion of Phase Two of the Big Bend 4 major outage.

For 2021, major production plant additions include $347.6 million for the first tranche of Future Solar. Another $354.7 million of major plant additions in 2021 is related to the completion of the first phase of the Big Bend Modernization.

For 2022, major production plant additions include $234.5 million for the second tranche of Future Solar and $445.7 million related to the completion of the first phase of the Big Bend Modernization. Further major additions in 2022 include $50.3 million for the Bayside Unit 1 Major Outage and Advanced Hardware Upgrades, as well as $54.5 million fort the Polk Dual Fuel Expansion Project.

The remainder of the additions for these years is attributable to prudently incurred annual sustaining capital expenditures required to maintain the operational and environmental reliability of the company's existing generating fleet and so that those generating units will remain used and useful for delivery of electric service to our customers.

Q. What major production plant projects are in Construction Work in Progress for 2022 as shown on MFR Schedule B-13.

A. For 2022, major production plant project balances in Construction Work in Progress include $377.1 million for the second phase of the Big Bend Modernization, $241.6

million for Future Solar, $35.3 million for Bayside Advanced Hardware, and $23.4 million for Distributed Generation.

Q. What is Tampa Electric's construction capital budget for Energy Supply in 2022 and 2023?

A. The Energy Supply construction capital budget totals $176.1 and $150.5 million for 2022 and 2023, respectively, as shown in Document No. 12 of my exhibit. This total is comprised of $101.7 and $126.5 million for recurring, non-expansion projects and $74.4 and $24.0 million for non-recurring, expansion projects in 2022 and 2023, respectively. These additions to rate base are prudent as described below.

Q. In general, how does Tampa Electric determine the construction program and capital budget for additional generation facilities?

A. Tampa Electric uses an Integrated Resource Planning ("IRP") process. The IRP process determines the timing, type, and amounts of additional resources required to maintain system reliability in a cost-effective manner. The process considers expected growth in customer demand, energy efficiency and conservation programs, existing and future demand-side management ("DSM") programs, and a wide range of supply-side generating technologies applicable to the company's service area. We also employ the Asset Management principles previously described in my direct testimony.

Q. What evaluations were performed before the company approved and began implementing its plans for Big Bend Modernization and Future Solar?

A. The specifics of the analyses used to develop and determine the cost-effectiveness of the Big Bend Modernization and the Future Solar are described in the direct testimony of Mr. Caldwell and Mr. Aponte, respectively.

Q. How does the company plan and manage its generation and other major capital improvement expansion projects?

A. The company has a mid-term planning process in place to manage its generation and other major capital improvement projects. As part of this process, the company conducts a screening analysis and develops a multi-year business plan. This plan includes capital and maintenance budget forecasts for projects deemed necessary to ensure safety, maintain or improve performance of existing stations, capacity, efficiency and reliability improvements, and environmental compliance. The company updates the business plan as new information is obtained.

Each year the company determines the capital plan for the following fiscal year. Information regarding generating unit availability, operating conditions, new regulations, and environmental compliance is reviewed and considered for inclusion in the capital plan. Some projects are required because of environmental or safety considerations or new regulations. Other projects are prioritized based upon their relative benefits. Through a review process, the projects are selected for inclusion in the next year's budget. These projects are also initiated and executed by a project team in a method like that for new generation projects. Each project goes through an estimating and approval process to ensure its benefit and need. These projects are monitored for cost, schedule, and desired performance throughout the process until they are completed and in-service.

Q. Does the company consider planned generation outages when preparing its annual capital budget?

A. Yes. Planned outages have a capital and expense element.

The capital costs associated with 2022 planned outages are described below in this section of my direct testimony. The expenses associated with the planned outages for 2022 are discussed in the next section of my direct testimony.

Planned outages are defined as those outage periods that are anticipated and planned well in advance of the actual outage period, typically at least one year in advance. Forced outages, on the other hand, are not planned or scheduled, and can be the result of an in-service failure or imminent failure of some generating unit component. In addition, forced outages are typically short in duration and have greatly reduced scope-of-work versus planned outages.

The 2022 planned unit maintenance durations are shown for each unit in MFR Schedule F-8, page 11 of 24. There are 24 planned outages scheduled in 2022. We have scheduled a total of 48 planned outage weeks across our system. The planned outage schedule varies from year to year based on the maintenance requirements of each generating unit and the need for adequate generating capacity in service to reliably meet demand throughout the year.

Except for the major planned outage at Bayside described below, the planned maintenance outage activity for 2022 is typical of the past and expected future planned outage requirements.

Q. You previously explained the company's production plant rate base additions from 2013 to 2021, why they were prudent, and that they continue to be used and useful to serve the company's customers. Would you now please describe and explain the major additions to production plant rate base that will occur in the 2022 test year?

A. The company's major Energy Supply capital projects that will be in service in all or part of 2022 include:

225 MW of Future Solar – Our 2022 plans reflect 225 MWac of Future Solar constructed in 2021 and in service in December 2021 at an estimated capital cost of $315.1 million.

Big Bend Unit 4 Natural Gas Upgrade – This project will deliver increased load capability on natural gas, will be completed during the Fall 2021 outage, and will have a capital cost of approximately $9.0 million.

436 MW Big Bend Modernization steam turbine CC component

- The steam-related or CC component of the Big Bend Modernization will be completed in December 2022 at an estimated capital cost of $495.2 million.

67 MW Bayside Unit 1 Advanced Hardware Upgrades - The first phase of the planned upgrades to Bayside will commence in 2022 and will be completed in 2023. The advanced hardware will increase generating capacity while also improving operational efficiency and flexibility. The estimated capital cost in 2022 is $20.0 million.

Bayside Unit 1 planned major outage – This project will address the steam turbine and steam valves, HRSG attemperators, steam turbine and CT auxiliaries, and CT controls upgrade and is expected to have a capital cost of approximately $7.9 million.

Polk Dual Fuel Expansion Project – Polk currently has dual fuel capability on CTs 2 and 3 and the addition of fuel oil capability on CTs 4 and 5 is planned for 2022 and is expected to have a capital cost of approximately $54.5 million.

Distributed Generation – In support of a streamlined approach to meeting winter peaks, distributed generation development will begin in 2021 and conclude in 2024. Utilizing reciprocating engine technology, the estimated 2022 capital cost is $48.6 million.

Q. Why are each of these major projects prudent and how will they benefit the company and its customers?

A. **225 MW of Future Solar** – Mr. Aponte provides a more detailed overview of the benefits of our Future Solar.

Big Bend Unit 4 Natural Gas Upgrade – The planned upgrade will provide dispatch flexibility of Big Bend Unit 4 and will provide additional fuel savings opportunities while natural gas is more economic than coal.

436 MW Big Bend Modernization steam turbine CC component – Mr. Caldwell's testimony thoroughly explains the benefits of Big Bend Modernization and our related 2022 plant additions.

67 MW Bayside Unit 2 Advanced Hardware Upgrades - Gas turbines require regular overhauls on time- and start-based intervals. The timing of these overhauls for Bayside Units 1 and 2 are 2022 and 2023, respectively. The company also will make an incremental investment over the base overhaul investments, which will result in significant increased generation capacity, improved heat rate performance, and operational flexibility. The added generation will come at an approximate cost of $403 per kW, which is significantly less than any other known alternative.

Bayside Unit 1 planned outage – All generating assets require major maintenance outages on a four to five-year rotation and Bayside Unit 1 is scheduled for 2022. The planned refurbishment of major generating assets delivers a high degree of availability and aids in optimizing operational efficiency.

Polk Dual Fuel Expansion Project – Dual fuel capability provides a level of protection from natural gas fuel shortages and from short-term price spikes in natural gas pricing.

Distributed Generation – With a goal of improving the customer experience and the overall reliability of our energy supply system, the addition of distributed generation will continue to diversify the generation portfolio.

Q. With these projects, what does the company expect its summer and winter reserve margins to be in 2022 and 2023?

A. The company's 2020 Ten Year Site Plan shows that in 2022 the summer reserve margin will be 29 percent and the winter reserve margin will be 20 percent. Following the completion of the planned 2022 projects, the 2023 summer reserve margin will be 36 percent and the winter reserve margin will be 22 percent. Solar generation does not contribute to the winter peak hour, which typically occurs at the hour of 7:01 to 08:00 a.m., resulting in higher summer reserve margins when the Solar *is* available at the system's peak time. The company must plan for its greatest load at the winter peak and a 20 percent reserve margin at that time. Solar generation, while not contributing to a peak capacity need in these analyses, provides zero-cost fuel and environmental benefits throughout the year.

Q. Does the company's proposed rate base for 2022 include any Property Held for Future Use?

A. Yes. MFR Schedule B-15 reflects approximately $11.6 million of property held for future use. This property was purchased as buffer land to prevent encroachment by surrounding residential development and to support the long-term and viable operation of the Big Bend Power Station.

2022 ENERGY SUPPLY O&M EXPENSES

Q. What are Tampa Electric's production O&M and non-recoverable fuel expenses budgeted for 2022 and how has the amount varied over time?

A. Document No. 13 of my exhibit shows the Tampa Electric Energy Supply department production O&M costs, excluding all costs recovered through cost recovery clauses, are budgeted to be $111.1 million in 2022. This is $8.7 million less than the amount incurred in 2013. In fact, O&M expenses (excluding cost recovery clauses) increased from $119.8 million in 2013 to a peak of $146.4 million in 2016.

Since 2016, Tampa Electric has reduced its production O&M expenses by transitioning to cleaner and more affordable sources of fuel with a concentration on natural gas operations and the addition of renewables such as Solar. At Big Bend, for example, which has historically been the company's primary solid fuel facility, we reduced operating expenses from a high of $79.6 million in 2015 to $43.0 million in 2022. This demonstrates some of the cost savings the company has achieved by switching from solid fuel to natural gas operations, which in turn have moderated our need for rate relief.

Q. How do these spending levels compare with what would be expected using the Consumer Price Index for Urban Consumers ("CPI-U") escalation factors using 2013 as a benchmark?

A. The CPI-U is the measure used by the Commission to benchmark O&M expenses for production plant. Document No. 14 of my exhibit shows that the actual expenses have generally been below what would be expected using the CPI-U as a cost escalator. The company implemented cost control measures from 2013 to 2020 to hold production O&M expenses below the levels expected with inflation. Our budgeted production O&M expenses for the 2022 test year are more than $28.6 million less than the 2012 O&M Benchmark Variance by Function as noted in MFR Schedule C-37.

Q. Please describe the change in outside professional services for the historical and projected test year.

A. Production (O&M) outside professional services, excluding all costs recovered through cost recovery clauses, included in the amounts on MFR schedule C-16, are approximately $26.3 million in 2022, compared to approximately $30.2 million in 2020. Primary drivers for this reduction include approximately $4.3 million included in the 2020 amount for completion of phase II of the Big Bend Unit 4 major outage, offset by approximately $3.0 million of outside services related to the 2022 Bayside major outage. Further reductions to the 2022 total are related to a $1.7 million reduction in solar outside services as that work will transition in-house. The remainder of the reduction of outside services expense in 2022 as compared to 2020 are a result of achieving cost efficiencies as the Company shifts from coal-fired generation to cleaner and more environmentally friendly sources of generation, which typically entail less maintenance than solid-fuel generation. Planned spending in 2022 is prudent and in line with historical expenditures.

Q. Please describe the favorable production O&M benchmark variances shown on MFR Schedules C-37, C-38, C-39, and C-41.

A. As shown on MFR Schedules C-37, C-38, C-39, and C-41, production O&M, excluding all costs recovered through cost recovery clauses, is budgeted to be $28.6 million, or 21.6 percent, favorable to the 2012 benchmark. The shift from coal-fired generation to cleaner and more environmentally friendly sources of generation has reduced overall cost of maintenance for the fleet. Production O&M steadily rose from 2012 to 2016 as maintenance costs on the solid fuel units continued to increase. The age of the units and wear and tear related to the use of solid fuel pushed maintenance costs higher each year until the spend peaked in 2016. In early 2017, commencement of operation of the Polk 2 Combined Cycle would effectively change the dispatch order and reduce the utilization of solid fuel- based units from baseline to economic dispatch. Cost controls and efficiencies achieved through the greater utilization of natural gas and later the addition of solar generation, resulted in a reduction of approximately 24.1 percent to labor costs, and approximately 40.5 percent reduction in outside services and materials costs, from the peak of production expense in 2016.

Q. How has the company managed to stay below the O&M benchmark for 2022 production expenses?

A. O&M production expenses have been trending down since 2016 as the company shifted from coal-fired generation to natural gas-fired generation. The Polk 2 Conversion dramatically changed the dispatch order of Polk 2 versus Big Bend units, resulting in lower O&M expenses. Polk Unit 2 has transitioned from primarily being a peaking facility to a baseload facility, and Big Bend has transitioned to an economic dispatch facility. This has resulted in less demand on Big Bend, which reduces wear and tear and the level of expenses we incur in Energy Supply. As part of our preparation for Big Bend Modernization, we have reduced staffing levels primarily through attrition and team members seeking opportunities elsewhere within the company. This benefited the overall O&M production expenses for Energy Supply.

Q. Does the company incur O&M expenses in conjunction with a planned outage?

A. Yes. Maintenance, as defined by FERC accounting instructions, conducted during planned outages is charged to O&M expense. Maintenance consists of large tasks that are performed infrequently and have a long duration. Typical examples are steam turbine inspections and repairs, replacement of large heat transfer surfaces in the boiler, and refurbishment of large motors and pumps. The maintenance performed during these outages is required to ensure the safe, reliable operation of the generating units.

Q. What is the O&M impact of planned outages on Tampa Electric's generating units in the 2022 test year?

A. Routine planned maintenance outages and the associated O&M costs, across all operating units is in line with historic spending and routine work scope. Planned major outages are required on a regular four- to five-year cycle and efforts are taken to stagger out these major outages to minimize the impact to O&M spending in any one year. For the 2022 test year, Bayside Unit 1 has a planned major outage, which is estimated to cost $6.0 million in O&M expense.

Q. Please describe the O&M work planned for the Bayside major planned outage.

A. The O&M work associated with the 2022 outage at Bayside station is estimated to cost $6.0 million. The scope of work includes the open and close activity; steam turbine rotor and blade inspection; bearing and seal cleaning, inspection, and maintenance; lift oil and seal oil flushes; and steam turbine valve cleaning, inspection, and maintenance.

Q. Has Tampa Electric taken other measures to control generation O&M costs while maintaining a safe and productive workplace?

A. Yes, Tampa Electric applies many different approaches to control cost, including the Asset Management methodologies previously described to manage O&M expenses. Other areas of focus include centralized contractor work planning and dispatch across all 3 generating facilities. Having a broader view of work demands allows for a more efficient and effective way to control contractor head count and contractor spending. We perform ongoing assessments of in-house capabilities and cost effectiveness versus an external contractor approach. Transitioning Solar operation and maintenance to in-house resources has provided cost reduction opportunities while also providing jobs for team members that may be impacted by the modernization of Big Bend.

Q. Is the overall level of production O&M expense for 2022 reasonable?

A. Yes. O&M expenses for 2022 are reasonable and will be managed close to 2020 levels. We will accomplish this by carefully managing the planned Bayside steam turbine major outage which, by itself, will have a $6.0 million impact to the O&M budget. We will mitigate inflation and standard labor increases by applying Asset Management procedures, implementing cost savings and continuous improvement initiatives, centralizing contractor coordination and contractor reductions, reducing wear and tear due to the transition to natural gas at Big Bend and Polk 1, and reducing staff levels at Big Bend.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony provides an overview of the company's generating system and its evolution since the 1950's and describes the company's future for its generating system. I describe how the Company's construction program and capital budget for 2022 and projections for 2023 and beyond are reasonable and prudent. I also demonstrate that the company's proposed O&M expenses for Energy Supply in the 2022 test year are reasonable and prudent. I explain how the company is using a disciplined approach to Asset Management to inform its decision-making in both Electric

Delivery and Energy Supply.

Tampa Electric’s Energy Supply area is safer, cleaner, and greener, and provides a better customer experience than in 2013; however, our work is not complete. To continue delivering the value our customers expect, we must plan for the long term and invest now to create an even cleaner, greener, and more efficient energy future. The projects described in my testimony will further improve our safety, reliability, customer experience, and environmental profile and are prudent and in the best interests of our customers.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

C. DAVID SWEAT

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

C. DAVID SWEAT

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

A. My name is Cecil David Sweat. My business address is 702 N. Franklin Street, Tampa, Florida, 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Renewable Energy.

Q. Please provide a brief outline of your educational background and business experience.

A. I have a bachelor's degree in Electrical Engineering and a master's degree in Engineering Management from the University of South Florida. I am a registered Professional Engineer in the state of Florida. I have more than 36 years of service with Tampa Electric working in the Substation, Transmission, Distribution, Meter, Grid Operations, Safety, Lighting, Vegetation Management, Skills Training and Renewable Energy areas.

Q. Have you previously testified or submitted written testimony before the Florida Public Service Commission ("Commission")?

A. Yes. I filed direct testimony in Docket No. 20000061-EI, which was a complaint against the company involving our commercial/industrial service rider. I have also participated in workshops regarding the company's storm preparedness plans and I participated in the agenda conference on Docket No. 20120038-EI, which involved the company's petition to modify its vegetation management plan.

Q. What are the purposes of your prepared direct testimony?

A. The purposes of my prepared direct testimony are to: (1) explain the company's plans to build 600 megawatts ("MW") of solar photovoltaic ("PV") generating facilities ("Future Solar") to serve its customers; (2) describe the Future Solar projects expected to be in service by December 1, 2021, December 1, 2022, and December 1, 2023, respectively; and (3) provide the projected installed costs for the projects.

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

A. Yes. Exhibit No. CDS-1 was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of 12 documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by C. David Sweat
Document No. 2	Magnolia Solar Project Specifications and Projected Costs
Document No. 3	Mountain View Solar Project Specifications and Projected Costs
Document No. 4	Jamison Solar Project Specifications and Projected Costs
Document No. 5	Big Bend II Solar Project Specifications and Projected Costs
Document No. 6	Laurel Oaks Solar Project Specifications and Projected Costs
Document No. 7	Riverside Solar Project Specifications and Projected Costs
Document No. 8	Palm River Dairy Solar Project Specifications and Projected Costs

Document No. 9	Big Bend III Solar Project Specifications and Projected Costs
Document No. 10	Alafia Solar Project Specifications and Projected Costs
Document No. 11	Wheeler Solar Project Specifications and Projected Costs
Document No. 12	Dover Solar Project Specifications and Projected Costs

Q. Are you sponsoring any of Tampa Electric's Minimum Filing Requirements ("MFR") schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR schedules listed in Document No. 1 of my exhibit. The contents of these MFR schedules were derived from the business records of the company and are true and correct to the best of my information and belief. MFRs B-11 and B-13 reflect the Future Solar projects described in my testimony.

Q. How does your prepared direct testimony relate to the prepared direct testimony of the company's other witnesses?

A. My direct testimony describes the utility-scale solar generation projects for which cost recovery is requested, as well as the projected in-service dates and installed costs per kW_{ac}. These costs are incorporated in the revenue requirement and Generation Base Rate Adjustment ("GBRA") amounts requested for 2022, 2023, and 2024, as described in the direct testimony of Tampa Electric witnesses A. Sloan Lewis and Jeffrey S. Chronister, respectively, the cost-effectiveness analysis presented by Tampa Electric witness Jose A. Aponte, and the proposed customer rates and miscellaneous charges submitted by Tampa Electric witness William R. Ashburn.

TAMPA ELECTRIC'S SOLAR PLANS

Q. Please describe the company's plan to install 600 MW of Future Solar.

A. As part of our strategy of transitioning to a cleaner, greener, generating portfolio, Tampa Electric plans to add 1.6 million solar modules in 11 new solar PV projects across its service territory in West Central Florida through 2023. This amounts to a total of 600 MW of cost-effective solar PV energy, which is enough electricity to power more than 100,000 homes. When the projects are complete, about 14 percent of Tampa Electric's energy will come from the sun.

These solar additions are a continuation of Tampa Electric's long-standing commitment to clean energy. The company has long believed in the promise of renewable energy because it plays an important role in our energy future. As a member of the Emera family of companies, Tampa Electric is committed to transitioning its power generation to lower carbon emissions with projects that are cost-effective for customers. To learn more about how customers want Tampa Electric to invest in a cleaner, greener future, refer to the direct testimony of Tampa Electric witness Melissa L. Cosby.

As of January 2021, the company has 655 MW of cost-effective solar projects in its generation portfolio. The additional 600 MW of cost-effective solar PV will be added to the company's generating fleet in three tranches. Tranche One projects, consisting of 226.5 MW of solar generation, are planned to be in service by December 1, 2021. Tranche Two consists of 224 MW and four projects, which will be in service by December 1, 2022. Tranche Three, 149.5 MW of solar generation, includes three projects and will be in service by December 1, 2023.

Q. What benefits accrue to the company and its customers from the company's plans to build the Future Solar in 2021, 2022 and 2023?

A. There are several. First, we have just completed the SoBRA solar and are able to apply the experience we have gained building utility scale solar. Second, purchasing modules, trackers, inverters and generating step up transformers in-bulk has allowed us to procure this equipment at favorable prices and enjoy economies of scale, which lowers the costs to our customers. Third, when possible, staging the construction of projects concurrently or one after another allows our contractors to efficiently manage their labor and equipment resources and minimize the costs they charge the company. Finally, we executed contracts to purchase inverters and tracking systems to secure the 26 percent Investment Tax Credit for all three Tranches. The ITC lowers the cost to our customers and requires all the assets to be in service by 2023.

TRANCHE ONE PROJECTS

Q. Please describe the Tranche One solar projects.

A. The Magnolia Solar Project ("Magnolia Solar"), Mountain View Solar Project ("Mountain View Solar"), Jamison Solar Project ("Jamison Solar") and Big Bend II Solar Project ("Big Bend II Solar") will be included in the first tranche. The projects use a single axis tracking system and design to optimize energy output for each site's conditions. Magnolia Solar is a 74.5 MW project located in Polk and Hillsborough Counties, Florida on approximately 577 acres of land. Mountain View Solar is a 52.5 MW project located in Pasco County, Florida on approximately 359 acres of land. Jamison Solar is a 74.5 MW project located in Polk County, Florida on approximately 695 acres of land. Big Bend II Solar is a 25 MW project located in Hillsborough County, Florida on approximately 191 acres of land. My exhibit contains project specifics, a general arrangement drawing, and projected installed costs in total and by category for each project.

Q. When does the company expect the Tranche One projects to begin commercial service?

A. Based on the current engineering, permitting, procurement, and construction schedules, the company expects the projects to be complete and in service on or before December 1, 2021.

Q. What arrangements has the company made to design and build the Tranche One projects?

A. The company used a competitive process to review qualifications and experience and identify and select full-service solar developers, followed by contract negotiations. To date, three full-service solar developers have been selected to provide project development and Engineering, Procurement, and Construction ("EPC") services for the first tranche of Tampa Electric solar projects.

Tampa Electric employed a Request for Information ("RFI") process to collect information from the bidders with respect to their qualifications, capabilities, and experience as full-service solar developers. The RFI was provided to more than 10 companies with whom Tampa Electric had met or discussed the development and construction of utility scale solar projects. Tampa Electric received 10 responses from the solar developers or solar EPC companies. The company used the information from the RFI responses to select a shortlist of six full-service solar developers.

The shortlisted developers were asked to provide pricing for solar PV projects that ranged in size from 25 to 75 MW. The pricing information was broken out for engineering and permitting, equipment, balance of system, installation, and interconnection. The projects were based on sites that Tampa Electric has purchased or for which it has site control. The pricing evaluation was conducted during May 2020 and included interviews with each developer.

In addition, Tampa Electric employed a screening and due diligence process to select its solar sites that includes geotechnical studies, environmental surveys, and wetland delineation. Each of the Tranche One sites was evaluated and selected after considering environmental assessments, size of the project, proximity to Tampa Electric transmission facilities, cost of land, and suitability of the site for solar PV construction, and each site is located within the company's service territory.

After reviewing the qualifications, experience, safety record, and cost proposals from the EPC contractors, Tampa Electric executed contracts with a full-service solar developer for each Tranche One project.

Tampa Electric selected Black & Veatch for the Magnolia Solar project, DEPCOM for Mountain View Solar and Big Bend II Solar, and Ecoplexus for the Jamison Solar project.

Q. What safety protocols are in place for contractors involved in constructing the Future Solar Projects?

A. The company's Contractor Safety Program is used to manage contractor safety at the project sites. It details the steps required for the EPC to maintain a safe working environment. Before the project begins, a senior management level meeting is held with the EPC to set expectations for successful implementation of the Health, Safety, and Environmental program. This meeting is followed by safety orientations and review of all EPC safety documentation. Tampa Electric utilizes ISN, an online contractor and supplier management platform, to ensure the EPC is maintaining the Company's minimum safety requirements, including Days Away / Restricted or Transfer rate (DART) and the Total Recordable Incident Rate (TRIR), active insurance, and effective written safety programs. We assign safety professionals to each solar site to assist Construction Supervisors in monitoring project activities for compliance of both Tampa Electric's and EPC Health, Safety, and Environmental programs.

Q. Has the company procured the land necessary for the solar projects?

A. Yes. Tampa Electric purchased land for the 74.5 MW Magnolia Solar project, the 52.5 MW Mountain View Solar project, and the 74.5 MW Jamison Solar project. The Magnolia Solar site is approximately 577 acres in size, and the Mountain View site consists of about 359 acres. The Jamison site is approximately 695 acres.

Tampa Electric is using previously purchased land for the 25 MW Big Bend II Solar project. This site is approximately 191 acres.

Q. What is the status of project design and engineering for the Tranche One projects?

A. The engineering and design of the Magnolia Solar project is complete. The company received the environmental resource permit in January 2021, and the county permit is expected in early April. Site work will begin immediately thereafter.

The engineering and design of the Mountain View Solar project is complete. The company received the environmental resource permit, and the county permit is expected in April. Site work will begin immediately thereafter.

The engineering and design of the Big Bend II Solar project is complete. The environmental resource permit is expected in mid-April, and a county permit is not required. Site work will begin upon receipt of the environmental resource permit.

The engineering and design of the Jamison Solar project is complete. The company received the environmental resource permit in March, and the county permit in February 2021. Site work will begin in April 2021.

Q. Has the company purchased PV modules necessary to construct the projects?

A. Tampa Electric solicited pricing from several module manufacturers and determined First Solar to be the best value based on pricing and performance. Tampa Electric purchased First Solar series 6 and 6 Plus modules for the entire 600 MW of Future Solar. The modules are part of a bulk purchase from First Solar in 2019, which enabled the company to lock in competitive prices and production slots.

Q. What other benchmarks demonstrate that the costs of the projects are reasonable?

A. A January 2021 NREL report that benchmarks EPC solar costs, "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020" shows 100 MW utility scale PV systems with single axis tracking costs average $1,350 per kW_{ac} excluding land costs. Tampa Electric's Tranche One EPC cost, excluding land costs, averages $1,187 per kW_{ac}.

PROJECTED INSTALLED COSTS

Q. What are the projected installed costs for the Tranche One projects?

A. The projected installed costs of the Tranche One projects with land are listed in the following table.

Magnolia	\$ 1,186 per kW_{ac}
Mountain View	\$ 1,333 per kW_{ac}
Jamison	\$ 1,336 per kW_{ac}
Big Bend II	\$ 1,352 per kW_{ac}

Q. What costs were included in these projections?

A. The projected total installed costs broken down by major category for the Tranche One projects are shown on Document Nos. 2 through 5 of my exhibit.

The projected costs shown in my exhibit reflect the company's best estimate of the cost of the projects; they include the types of costs that traditionally have been allowed in rate base and are eligible for cost recovery. These costs include EPC costs; development costs including third party development fees, if any; permitting and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection cost and modules and equipment costs; costs associated with electrical balance of system, structural balance of system; and other traditionally allowed rate base costs.

Q. Are Allowance for Funds Used During Construction ("AFUDC") costs included in your cost estimates?

A. No. Mr. Jose Aponte added AFUDC to the project costs I provided and used the total cost, including AFUDC, when analyzing project cost-effectiveness.

Q. How were the projected cost amounts in your exhibit developed?

A. Tampa Electric worked with developers and suppliers to determine the all-in costs for the Tranche One projects and used an iterative approach to update project costs as site due diligence and engineering and design were conducted. This includes negotiating and executing agreements directly with manufacturers and suppliers for modules, inverters, trackers and racking, and Generator Step-up Unit ("GSU") transformers, reviewing equipment specifications and pricing, reviewing the scope of work and balance of system costs, and acquiring land and cost estimates to engineer, permit, and construct the projects. The fixed O&M amounts were developed by our solar operations group based on their experience operating our first 600 MW of solar, i.e., the SoBRA solar.

Q. How did the company calculate the cost of land to be used in the calculation of the project's projected installed cost?

A. The costs of the land for the project sites follow; they are calculated using the actual purchase price of the land. Big Bend II land is $0 because we used available buffer land at Big Bend Power Station.

Magnolia	$5,474,886 or $ 9,489 per acre
Mountain View	$7,618,517 or $21,221 per acre

Jamison	$9,708,545	or	$13,969 per acre
Big Bend II	$ 0		

TRANCHE TWO PROJECTS

Q. Please describe the Tranche Two solar projects.

A. The Laurel Oaks Solar Project ("Laurel Oaks Solar"), Riverside Solar Project ("Riverside Solar"), Palm River Dairy Solar Project ("Palm River Dairy Solar"), and Big Bend III Solar Project ("Big Bend III Solar") will be included in the second tranche. These projects will use a single axis tracking system and are designed to optimize energy output for each set of site conditions. Laurel Oaks Solar is a 66.8 MW project located in Hillsborough County, Florida on approximately 515 acres of land. Riverside Solar is a 65 MW project located in Hillsborough County, Florida on approximately 530 acres of land. Palm River Dairy Solar is a 70 MW project located in Pasco County, Florida on approximately 548 acres of land. Big Bend III Solar is a 22.2 MW project located in Hillsborough County, Florida on approximately 93 acres of land.

My exhibit contains project specifics, a general arrangement drawing, and projected installed costs in total and by category for each project.

Q. When does the company expect the Tranche Two projects to begin commercial service?

A. Based on the current engineering, permitting, procurement, and construction schedules, the company expects the projects to be complete and in service on or before December 1, 2022.

Q. What arrangements has the company made to design and build the Tranche Two projects?

A. The Tranche Two Solar projects: Laurel Oaks Solar, Riverside Solar, Big Bend III Solar, and Palm River Dairy Solar, were designed and will be built using the same general contractual arrangements and processes and competitive bid process that I described for the Tranche One projects.

Tampa Electric selected Black & Veatch and executed a contract for project development and EPC services for the Laurel Oaks Solar project. The selection process is currently underway for the remaining Tranche Two projects: Riverside Solar, Big Bend III Solar, and Palm River Dairy Solar.

Q. Has the company procured the land necessary for the solar projects?

A. Yes. Tampa Electric has purchased land for the Laurel Oaks Solar and Riverside Solar projects, and the company employed the same screening and due diligence process to select the Tranche Two project sites as I described for the Tranche One projects. The Laurel Oaks site is approximately 515 acres in size and is located in Tampa Electric's retail service territory. The Riverside Solar site is approximately 530 acres in size and is in the company's retail service territory.

Tampa Electric is utilizing existing buffer land for the 22.2 MW Big Bend III Solar project. The site is approximately 93 acres in size and is in Tampa Electric's retail service territory.

Tampa Electric has a purchase option on land for the Palm River Dairy Solar project and is completing its due diligence. Once the due diligence is completed the company plans to purchase the land in Q2 2021. The site is approximately 548 acres in size and is in the company's retail service territory.

Q. What is the status of project design and engineering for the Tranche Two projects?

A. The engineering and design of the Laurel Oaks Solar project is underway. The environmental resource permit is expected in May 2021 and the county permit is expected in June 2021. Site work will begin first quarter of 2022.

The engineering and design of the Riverside Solar project will begin in the second quarter of 2021. Tampa Electric expects to submit permit applications during the second quarter of 2021. Site work will begin first quarter of 2022.

The engineering and design of the Big Bend III Solar project will begin in the second quarter of 2021. The company will submit permit applications during the second quarter of 2021. Site work will begin first quarter of 2022.

The engineering and design of the Palm River Dairy Solar project will begin once the land purchase has been finalized. Tampa Electric expects to submit permit applications in the second quarter of 2021. Site work will begin first quarter of 2022.

Q. What other benchmarks demonstrate that the costs of the projects are reasonable?

A. Tampa Electric's Tranche Two project EPC cost averages \$1,111 per kW_{ac}, excluding land costs. This compares favorably to the January 2021 NREL report benchmark's cost of \$1,350 per kW_{ac} excluding land costs, which I previously discussed.

TRANCHE TWO PROJECTED INSTALLED COSTS

Q. What are the projected installed costs for the Tranche Two projects?

A. The projected installed costs of the Tranche Two projects are as follows.

Laurel Oaks	\$1,170 per kW_{ac}
Riverside	\$1,241 per kW_{ac}
Palm River Dairy	\$1,183 per kW_{ac}
Big Bend III	\$1,275 per kW_{ac}

Q. Did you include the same types of costs and use the same cost estimation techniques for Tranche Two projects that you described for the Tranche One projects earlier in your testimony?

A. Yes. The projected total installed costs broken down by major category for the Tranche Two projects are shown on Document Nos. 6 through 9 of my exhibit.

The project land costs follow.

Laurel Oaks	$4,473,025 or $ 8,692 per acre
Riverside	$8,835,441 or $16,671 per acre
Palm River Dairy	$7,830,000 or $14,288 per acre
Big Bend III	$ 0

TRANCHE THREE PROJECTS

Q. Please describe the Tranche Three solar projects.

A. The Alafia Solar Project ("Alafia Solar"), Wheeler Solar Project ("Wheeler Solar"), and Dover Solar Project ("Dover Solar") will be included in the third tranche. These are single axis tracking configurations that will be designed to optimize energy output, given site-specific conditions. Alafia Solar is a 50 MW project located in Polk County, Florida on approximately 408 acres of land. Wheeler Solar is a 74.5 MW project located in Polk County, Florida on approximately 464 acres of land. Dover Solar is a 25 MW project located in Hillsborough County, Florida on approximately 177 acres of land.

My exhibit contains project specifics, a general arrangement drawing, and projected installed costs in total and by category for each Tranche Three project.

Q. When does the company expect the Tranche Three projects to begin commercial service?

A. Based on the current engineering, permitting, procurement, and construction schedules, the company expects the projects to be complete and in service on or before December 1, 2023.

Q. What arrangements has the company made to design and build the Tranche Three projects?

A. The Tranche Three Solar projects: Alafia Solar, Wheeler Solar, and Dover Solar will be designed and built using the same general contractual arrangements and processes and competitive bid process that I described for the Tranche One and Tranche Two projects.
The EPC selection process is ongoing for each Tranche Three project.

Q. Has the company purchased land for the Tranche Three solar projects?

A. Yes. Tampa Electric purchased land for the Alafia and Dover projects and entered a purchase option on the land for the third project. The company employed the same screening and due diligence process to select the Tranche Three project sites as I described for the Tranche One and Tranche Two sites. The Alafia site is approximately 408 acres in size and is located in Tampa Electric's retail service territory. The Dover site is approximately 177 acres in size and is within the company's service territory.

Tampa Electric has a purchase option on land for the Wheeler Solar project and is completing its due diligence. Once the due diligence is completed the company plans to purchase the land in Q2 2021. The Wheeler site is approximately 464 acres in size and is within the Tampa Electric service territory.

Q. What is the status of project design and engineering for the Tranche Three projects?

A. Tampa Electric expects the Alafia Solar engineering and design to begin during the third quarter of 2021, and permit applications will be submitted thereafter. Site work will begin during the first quarter of 2023.

Tampa Electric will begin engineering and design of the Wheeler Solar project after the site is purchased. Permit applications will be submitted thereafter, and site work will begin in the first quarter of 2023.

The Dover Solar project engineering and design will begin in the fourth quarter of 2021. Permit applications also will be submitted in the fourth quarter of 2021. Site work will begin first quarter of 2023.

Q. What other benchmarks did the company use to ensure that the costs of the Future Solar projects are reasonable?

A. Tampa Electric's Tranche Three project EPC cost averages \$1,087 per kW_{ac}, excluding land costs. This compares favorably to the January 2021 NREL report benchmark cost of \$1,350 per kW_{ac} excluding land costs, which I previously discussed.

TRANCHE THREE PROJECTED INSTALLED COSTS

Q. What are the projected installed costs for the Tranche Three projects?

A. The projected installed costs of the Tranche Three projects follow.

Alafia	\$ 1,252 per kW_{ac}
Wheeler	\$ 1,154 per kW_{ac}
Dover	\$ 1,375 per kW_{ac}

Q. Did you include the same types of costs and use the same cost estimation techniques for Tranche Three projects that you described for the Tranche One and Two projects earlier in your testimony?

A. Yes. The projected total installed costs broken down by major category for the Tranche Three projects are shown on Document Nos. 10 through 12 of my exhibit.

The Tranche Three project land costs are as listed below.

Alafia	\$6,376,864 or \$15,630 per acre
Wheeler	\$9,475,578 or \$20,422 per acre
Dover	\$4,520,591 or \$25,505 per acre

TRANCHES ONE, TWO, AND THREE PROJECTED COSTS

Q. Are the project costs reasonable?

A. Yes. Our track record estimating and controlling the costs associated with our first 600 MW of SoBRA solar projects is good. The actual costs of the projects in the first three traches came in very close to our estimates. We have used the same cost estimating and control procedures for our Future Solar projects. We control project costs using competitive bidding processes, diligent oversight of EPC contractors, negotiation of cost-effective equipment purchases to include ITC credits for inverters and tracking systems, and project management to ensure the projects remain on time and on budget. These project costs are below recent benchmark prices, as I previously discussed.

SUMMARY

Q. Please summarize your prepared direct testimony.

A. Tampa Electric is building three tranches totaling 600 MW of solar generation projects. The first, second, and third tranches consist of single axis tracking solar PV projects in 226.5 MW, 224 MW, and 149.5 MW increments, respectively. The projects of each tranche will enter service at one-year intervals beginning in December 2021. Tranche One includes Magnolia Solar in Polk and Hillsborough Counties with 74.5 MW of capacity on 577 acres; Mountain View Solar in Pasco County providing 52.5 MW of capacity on 359 acres; the 74.5 MW Jamison Solar project in Polk County on 695 acres; and Big Bend II Solar in Hillsborough County with 25 MW on 191 acres. The projected costs of Magnolia Solar, Mountain View Solar, Jamison Solar, and Big Bend II Solar are $1,186, $1,333, $1,336, and $1,352 per kW_{ac}, respectively.

Tampa Electric will build the Laurel Oaks Solar project in Hillsborough County with 66.8 MW on 515 acres; the Riverside Solar project in Hillsborough County providing 65 MW of capacity on 530 acres; Palm River Dairy Solar in Pasco County 70 MW of capacity on 548 acres; and Big Bend III Solar in Hillsborough County providing 22.2 MW of capacity on 93 acres. The projected costs of Laurel Oaks Solar, Riverside Solar, Jamison Solar, and Big Bend III Solar are $1,170, $1,241, $1,183, and $1,275 per kW_{ac}, respectively.

Tranche Three includes the 50 MW Alafia Solar project in Polk County on 408 acres; Wheeler Solar in Polk County, which adds 74.5 MW of capacity on 464 acres; and the 25 MW Dover Solar project in Hillsborough County on 177 acres. The projected costs of Alafia Solar, Wheeler Solar, and Dover Solar are $1,252, $1,154, and $1,375 per kW_{ac}, respectively.

Tampa Electric controls project costs using competitive bidding processes, diligent oversight of EPC contractors, negotiation of cost-effective equipment purchases, and project management to ensure the projects remain on time and on budget. These project costs are below recent benchmark prices.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

(Transcript continues in sequence in Volume 3.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

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

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

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

DATED this 1st day of November, 2021.

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