BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240026-EI

Petition for rate increase
by Tampa Electric Company.
_______________________________________/

DOCKET NO. 20230139-EI

Petition for approval of 2023
depreciation and dismantlement
study, by Tampa Electric Company.
_______________________________________/

DOCKET NO. 20230090-EI

In re: Petition to implement 2024
generation base rate adjustment
provisions in paragraph 4 of the
2021 stipulation and settlement
agreement, by Tampa Electric Company.
_______________________________________/

VOLUME 6 - PAGES 1091 - 1297

PROCEEDINGS: HEARING

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

DATE: Wednesday, August 28, 2024

TIME: Commenced: 8:00 a.m.
Concluded: 9:15 p.m.

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

TRANSCRIBED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for
the State of Florida at Large

APPEARANCES: (As heretofore noted.)

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
21	As identified in the CEL		1087
145	As identified in the CEL		1087
370	As identified in the CEL		1088
725-726	As identified in the CEL		1088
22	As identified in the CEL		1294
639	As identified in the CEL		1295
649	As identified in the CEL		1295

P R O C E E D I N G S

(Transcript follows in sequence from Volume 5.)

CHAIRMAN LA ROSA: TECO, let's go ahead and introduce your next witness.

MR. WAHLEN: Thank you, Mr. Chairman. Tampa Electric calls Chip Whitworth.

CHAIRMAN LA ROSA: Mr. Whitworth, I do not believe you have been administered the oath. Do you mind standing?

Whereupon,

CHIP WHITWORTH

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

THE WITNESS: I do.

CHAIRMAN LA ROSA: Thank you.

Have a seat. Get settled in. We will give you a few seconds to get organized.

TECO, you are ready -- or we are ready when you are.

MR. MEANS: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MEANS:

Q Good morning, Mr. Whitworth.

A Hey. Good morning.
Q Can you please state your full name for the record?
A Chip Whitworth.
Q And you were just sworn, correct?
A I was.
Q Who is your current employer and what is your business address?
A Tampa Electric Company. Business address is 702 North Franklin Street, Tampa, Florida.
Q Did you prepare and cause to be filed in this docket, on April 2nd, 2024, prepared direct testimony consisting of 47 pages?
A I did.
Q And did you prepare and cause to be filed in this docket, on July 2nd, 2024, prepared rebuttal testimony consisting of 13 pages?
A I did.
Q Do you have any additions or corrections to your prepared direct or rebuttal testimony?
A I do not.
Q If I were to ask you the questions contained in your prepared direct and rebuttal testimony today, would your answers be the same?
A They would.

MR. MEANS: Mr. Chairman, Tampa Electric requests that the prepared direct and rebuttal testimony of Mr. Whitworth be inserted to the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Chip Whitworth was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CHIP WHITWORTH

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

A. My name is Chip Whitworth. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or the "company"), and I am the Vice President of Electric Delivery.

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

A. I have responsibility for all aspects of Electric Delivery which include Safety; Environmental Compliance; Customer Reliability; Transmission and Distribution Grid and Energy Control Center; Transmission, Substation, and Distribution Engineering and Construction; Storm Protection Plan ("SPP"); Asset Management; Meter Operations; Operational Technology and Strategy; Lighting Operations; Telecommunications; and Fleet Operations. I provide direct leadership to all the company's Electric

Delivery Directors and lead a team of approximately 1,050 team members.

My duties and responsibilities include the oversight of all functions within Tampa Electric's Electric Delivery Department including the planning, engineering, operation, maintenance, and restoration of the transmission, distribution, and substation systems; operation of the distribution and energy control centers; administration of tariffs and compliance; execution of the company's Transmission and Distribution ("T&D") strategic solutions including advanced metering infrastructure ("AMI"), outdoor and streetlight light-emitting diode ("LED") conversion project, and Advanced Distribution Management System ("ADMS"); line clearance activities; and fleet and equipment. In addition, I am responsible for the safe, timely, and efficient implementation of Tampa Electric's storm restoration plan.

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

A. Yes. I filed direct testimony in Docket No. 20230019-EI, Tampa Electric's Petition for recovery of costs associated with named tropical systems during the 2018-2022 hurricane season and replenishment of storm reserve. I also provided testimony for two Transmission Line Siting Act ("TLSA") projects; Willow Oak,- Wheeler,- Davis and Lake Agnes to Gifford were the two projects.

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

A. I graduated from The University of South Florida with a Bachelor of Science in Civil/Structural Engineering ("BSCE") and a Master of Business Administration ("MBA"). I have more than 27 years of experience in the energy industry, all of which has been at Tampa Electric. Prior to becoming Vice President of Electric Delivery at Tampa Electric in 2022, I held the position of Vice President of Safety beginning in 2021. Prior to taking that role, my work experience included approximately 24 years in Electric Delivery and Energy Supply where I worked as an engineer and held various engineering and operations leadership positions.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to (1) describe the company's T&D system; (2) describe the changes to the T&D system since the company's last base rate case; (3) describe the company's future plans for its T&D system and our grid modernization strategy; (4) demonstrate that the company's T&D plant (*i.e.*, electric delivery) construction program and capital budget for 2025 is reasonable and prudent; and (5) show that the company's proposed level of operations and maintenance expense ("O&M") for Electric Delivery in the 2025 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. CW-1, entitled "Exhibit of Chip Whitworth" 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 Chip Whitworth

Document No. 2	FPSC Adjusted Reliability Trends
Document No. 3	Service Area Customer Demand – Growth
Document No. 4	Electric Delivery Capital Summary 2022 - 2025
Document No. 5	DOE ICE Calculator Results
Document No. 6	Line Loss Reduction
Document No. 7	Grid Reliability and Resilience Project Schedule
Document No. 8	Service Territory Map

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 2025 test year and otherwise discussed in your direct testimony include amounts related to the company's SPP?

A. No. The rate base and O&M amounts for the 2025 test year do not include SPP O&M.

TRANSMISSION AND DISTRIBUTION SYSTEM OVERVIEW

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 nearly 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. Please refer to Document No. 8 of my exhibit entitled: "Service Territory Map".

Tampa Electric's transmission system consists of nearly 1,332 circuit miles of overhead facilities, including approximately 25,296 transmission poles and structures. The company's transmission system also includes approximately ten circuit miles of underground facilities.

The company's distribution system consists of approximately 6,137 distribution circuit miles of overhead facilities, and approximately 266,773 poles. The distribution system also includes approximately 6,475 circuit miles of underground facilities.

The company currently has 238 T&D substations.

Q. What role does safety play in Electric Delivery?

A. Safety is the top priority, a core value at Tampa Electric, and is integral to the work that we perform. Electric Delivery is committed to the belief that all injuries are preventable. In 2018, Electric Delivery implemented a Safety Management System ("SMS") designed to ensure compliance with Occupational Safety and Health Administration ("OSHA") regulations and to follow OSHA recommended practices. The SMS consists of 10 elements including: 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.

Through 2021 and 2022 Tampa Electric Company worked over 6 million work hours without a lost-time injury. Through December 2023, Tampa Electric's lost-time injury rate is 16 percent better than the company's five-year average.

Additionally, Electric Delivery is focusing on preventative measures such as high energy identification, hazard recognition, and mitigation through new job risk briefing tools and training sessions. These tools teach

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workers to identify high energy sources present and to not proceed with work until barriers are installed. Industry trends show that most Serious Injuries and Fatalities ("SIF") are the result of unmitigated high energy exposure contacting a worker.

Electric Delivery has a robust community-outreach safety program where we communicate in-person with first responders, educators, and community leaders about electrical facilities and how that relates to public safety.

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, as described below.

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 improvement processes, the establishment of asset management responsibilities throughout the organization, and ensuring team members are empowered with industry best practices through awareness, training, and implementing these best practices.

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 operations 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, ensures full utilization of assets and often life extensions of assets, and improves efficiency and reliability – all of which promote a good customer experience.

PROGRESS SINCE TAMPA ELECTRIC'S LAST BASE RATE PROCEEDING

Q. How has the company's T&D system continued to evolve since the company's last base rate proceeding in 2021?

A. Since 2021, Tampa Electric's Electric Delivery department has continued to ensure that we can provide resilient, safe, and reliable power to our current and future customers.

One of the ways that the T&D system has evolved is through system expansion. We expanded our overhead transmission system by approximately 18 circuit miles and expanded our underground distribution system by approximately 760 circuit miles. Additionally, the company placed 15 new substations in service and added approximately 670 single and three phase reclosing devices on the distribution system.

Another way the T&D system changed is through a shift to primarily providing distribution service through underground equipment, which is more reliable and resilient in extreme weather conditions. Since 2021, we have reduced our overhead distribution system by approximately 109 miles even as the overall mileage of the distribution system has grown. In 2023, Electric Delivery transitioned to a primarily underground distribution system, with more installed underground circuit miles than overhead. The ratio of underground to overhead circuit miles will continue to increase as the SPP lateral undergrounding program matures and as new single family housing developments continue to propagate.

These capital investments since the last base rate case were required to support the substantial increase in customer demand and support the economic development in Tampa Electric's service territory. For example, since 2016, customer system demand in terms of Mega Volt Ampere ("MVA") has cumulatively increased by 9.7 percent.

This growth in demand is directly correlated to our customer growth rate. Since 2016, Tampa Electric has had an overall average annual customer growth rate of 2.1 percent. The cumulative overall growth has been 17.7 percent. However, this does not reflect the rapid growth and expansion within areas of Tampa Electric's service territory. For example, the South Hillsborough, Winter Haven, and Dade City service areas have seen cumulative customer increases of 53.3 percent, 22.8 percent, and 17.8 percent respectively. Please see Document No. 3 of my exhibit entitled: "Service Area Customer Demand".

The customer demand growth analysis shows that a significant influx of new customers are moving to formerly rural areas within our service territory requiring electric system expansion, *i.e.*, new substations, transmission lines, upgraded distribution services, and relocations of existing facilities to accommodate roadway improvements.

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

A. The reliability of our service has the most impact on our customer experience. We track a variety of industry recognized reliability metrics that reflect how our Electric Delivery system performs from a customer's perspective.

The company 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 System Average Interruption Frequency Index ("SAIFI") and the Customer Average Interruption Duration Index ("CAIDI").

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

Tampa Electric sets reliability goals for both SAIDI and MAIFIe annually and reports these results to the Commission in compliance with Rule 25-6.0455, Florida Administrative Code, which requires investor-owned utilities ("IOU") 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 six or more sustained outages annually. CEMI-5 yearly results are consistently improving each year, as shown later in my testimony.

Q. Has the company's delivery system reliability improved since 2021?

A. Yes, the company's T&D reliability has steadily improved since 2021. Our SAIDI improved from a high of 84.5 in 2021 to a low of 57.27 in 2023, and MAIFIe improved from a high of 6.5 in 2021 to a low of 6.44 in 2023. CEMI-5 improved from 9,744 in 2021 to 1,022 in 2023. These results are reflected in Document No. 2 of my exhibit entitled: "FPSC Adjusted Reliability Trends".

Q. How did the company achieve these improvements in Electric delivery system reliability?

A. Tampa Electric attributes these improvements to work performed in four major areas: the Asset Management Program, our Annual Distribution Reliability Plan, operational changes, and the SPP.

Q. Please describe the company's achievements through the Asset Management Program since 2021.

A. Tampa Electric completed several activities under the Asset Management Program that improved system reliability. For example, Tampa Electric inspected 2,691 of the company's 3,099 distribution switchgears. This inspection showed that some of these switchgears are at the end of life, while for others replacement can be deferred. Based on these findings, the company moved from a time-based replacement prioritization to a risk-based prioritization. This change will prioritize replacement of switchgear that are at their end of useful life, instead of simply prioritizing the oldest equipment, and will maximize the use of switchgear that has remaining life. Through this effort, Tampa Electric has replaced 444 of these switchgears since 2019.

As another example, the company used Asset Management analysis to prioritize proactive replacement and maintenance of medium power transformers, 69 kV oil circuit breakers, and 13 kV distribution circuit breakers. This proactive replacement and maintenance prioritization prevents potential customer outages, maximizes the useful life of installed assets, and mitigates risks associated with equipment failures. Our Asset Management processes also consider the impact of equipment failures to the community in the prioritization of maintenance. In 2022 and 2023, Tampa Electric proactively replaced 28 of our 13 kV distribution circuit breakers, including all breakers that feed one of the most critical facilities to our customers, Tampa International Airport.

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 uses the SAIDI, MAIFIe, SAIFI, and CEMI-5 results to determine which circuits to target for reliability improvement. We also evaluate circuit outages over a five-year period to determine the most frequent outage locations as well as the most frequent root causes. This allows us to effectively deploy capital to the circuits that have below average performance.

The results of these evaluations are used to identify the type of equipment needed to improve reliability, such as automatic feeder and lateral reclosers, and fault detectors, and to install that equipment in places that will optimize reliability improvements. The company has achieved significant reliability improvements through this targeted approach of research and field device installation.

Q. What operational changes has the company made to improve reliability?

A. The company made operational changes within the control room to dispatch resources more effectively for outages. For example, Tampa Electric has line crews available during the night that can instantly mobilize to an outage. This avoids mobilizing line workers from their homes, which adds considerable time to restoration.

From an engineering perspective, Tampa Electric has utilized a relay and protection scheme known as "sequence coordination" between circuit breakers and lateral reclosers to better sectionalize momentary interruption impacts, leading to significant MAIFIe improvements.

Q. Please briefly describe the company's progress under the SPP program over the last several years.

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. The Commission approved the company's second SPP in December of 2022, through Order PSC-2020-0293-AS-EI, which was issued on August 28, 2020.

Between April 2020 and the end of 2023, Tampa Electric completed the following SPP activities:

- 27 Feeder Hardening projects.
- 239 Lateral Undergrounding projects.
- 355 circuits (2,180 miles) trimmed under the Supplemental Vegetation Management program.
- 270 circuits (1,440 miles inspected, 3,680 spans trimmed and 1,917 hazard trees removed) under the Mid-Cycle Vegetation Management program.

Q. Can you please provide an update on how the SPP Program has impacted the reliability of the system during storms?

A. Our SPP activities have resulted in significant improvement in system performance during and after extreme weather events, which improves the customer experience. This improvement is best illustrated by comparing system performance during Hurricane Irma, which predated the first SPP, and Hurricane Ian in September of 2022. During Hurricane Ian, wind speeds remained above 40 miles per hour for 8.5 hours, as compared to only 1.5 hours during Hurricane Irma. Despite these more severe weather conditions, the company saw significantly improved performance in several areas, including:

- A 57 percent reduction in the number of outages on the 18 circuits that were hardened under the Feeder Hardening Program, and zero pole or feeder wire failures on those circuits. There were four pole failures on non-hardened feeders within 1,000 feet of hardened feeders, which indicates that there would have been more pole failures but for the company's hardening efforts.
- None of the laterals that were undergrounded before Hurricane Ian experienced an outage during Ian. The company examined areas within 1,000 feet of each underground conversion project and identified four pole failures, indicating that weather conditions in those areas could have caused damage to overhead lateral equipment if it had been present.
- Circuits that received Supplemental Vegetation Management had a 20 percent reduction in the number of outages.

- Circuits that received Mid-Cycle Vegetation Management had a five percent reduction in the number of outages.
- Circuits that received both Supplemental and Mid-Cycle Vegetation Management had a 43 percent reduction in outages.

Q. Have the improvements made to the company's system performance and reliability since 2021 improved Tampa Electric's customer experience?

A. Yes. In 2023, Tampa Electric scored better than the industry average for every residential customer satisfaction criterion (as measured by J.D. Power), including Power Quality and Reliability, which is ranked at the top of the second quartile nationally (40^{th} out of 149 brands). In the South Large segment, Tampa Electric is ranked third out of 12 brands, which is the highest ranked Florida brand in our segment for Power Quality and Reliability. On the business side, Tampa Electric also scored better than the industry average and is ranked in the second quartile nationally (37^{th} out of 77 brands) for Power Quality and Reliability. Between 2022 and 2023, when most other satisfaction criterion scores decreased, Tampa Electric's Power Quality and Reliability score increased by three points.

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FUTURE PLANS FOR TRANSMISSION AND DISTRIBUTION SYSTEM

Q. Will the company need to continue investing in its T&D system?

A. Yes. Tampa Electric witnesses Archie Collins, Karen Sparkman, Carlos Aldazabal, Chris Heck, and David Lukcic 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 T&D system to ensure that it will be safe, resilient, secure, reliable, compatible with distributed generation and energy storage, and will provide the data customers want for managing their electric service. Accordingly, our long-term plans include significant investments for grid resilience and reliability. 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; improve reliability; reduce restoration times; increase resiliency; improve grid planning; allow new customer programs and new rate designs; and provide data directly to customers so they can better manage their electric service. Tampa Electric will implement a group of projects, known collectively as the Grid Reliability and Resilience Projects, including a Grid Communication Network Project, to meet these needs.

Q. What are the Grid Reliability and Resilience Projects?

A. The Grid Reliability and Resilience Projects are components of a comprehensive program that builds on Tampa Electric's existing grid modernization strategy. The program includes more than 40 interdependent projects across the six primary domains of the electric system including: (1) telecommunications; (2) control center operational technology; (3) back-office information technology; (4) distributed energy resources ("DER") infrastructure; (5) field devices; and (6) substations. When completed, these changes to the grid will create a "system of systems" with many benefits for Tampa Electric's customers. Tampa Electric's goal is to complete all component projects by the end of 2030.

Mr. Lukcic provides greater detail regarding the Grid Reliability and Resilience Projects planned for the next several years in his direct testimony.

Q. Why is Tampa Electric aggregating the Grid Reliability and Resilience Projects?

A. Aggregating these projects results in more efficient capital spending and unlocks enhanced functionality as system elements are deployed. Pursuing these activities as individual projects would hinder the integration of the program and increase the risk of project delays, rework, and scope changes.

Q. What do you mean when you describe these projects as interdependent?

A. Through the Grid Reliability and Resilience Projects, Tampa Electric will deploy infrastructure in a coordinated program that will enable the company to exchange electricity and information across the six grid domains, and to exchange information from the grid edge to the company's control and information technology ("IT") and operations technology systems.

For example, sensors on lines and substations in the field device domain can continuously monitor circuits for faults or anomalies. Monitoring data from these field devices is relayed through the telecommunications domain to the control system operational technology domain. These control systems can then take appropriate corrective actions by sending signals back to the field devices.

Q. Why are the Grid Reliability and Resilience Projects necessary?

A. These projects are necessary to replace obsolete systems and equipment that have reached end of life as well as meeting customer demands for greater reliability, greater access to data, and to adapt to changes in how our customers consume energy.

Reliable and resilient electric service underpins everything Tampa Electric does. Our customers are increasingly demanding an "always-on" experience. As shown elsewhere in my testimony, our reliability metrics have significantly improved in recent years. The Grid Reliability and Resilience Projects are the next step in the journey to world-class reliability to help meet customer expectations.

The Grid Reliability and Resilience Projects will result in a better integration of back-office systems with field operations, which will lead to better in-service timelines and a simpler, more streamlined interaction with Tampa Electric for customers. This will allow customers access to more data to help them make informed decisions about energy usage and provide better visibility into the status of work we are performing for them.

These projects are also necessary to respond to changes in how energy is consumed and produced, including the rapid growth of electric vehicle ("EV") adoption and the proliferation of customer owned distributed energy resources ("DER"), and to replace obsolete and unsupported operating systems. Tampa Electric forecasts that by 2030, there will be over 200,000 EV charging on the company's grid, consuming approximately 944 gigawatt-hours ("GWh") of energy and adding up to 282 megawatts ("MW") of peak demand. Some of these vehicles may also have vehicle-to-grid capability, meaning they can inject power back into the grid. The company also forecasts that by 2030, the number of customer-owned DER on Tampa Electric's system will triple from the current count of 25,000 to approximately 75,000. This level of DER is equivalent to a nameplate generating capacity of 770 MW resulting in 1,212 GWh of energy going back into homes/businesses with excess energy going back into the company's distribution grid.

Q. What effect will the increasing adoption of EV and customer owned DER have on Tampa Electric's distribution system?

A. Tampa Electric's distribution system is designed for a centralized generation model under which power is generated at large, centralized power plants and transmitted and distributed over long distances to end users. With the proliferation of EV and DER, the grid will now experience two-way power flows. Through our AMI, Tampa Electric has begun to detect areas of elevated reverse loading due to concentrated DER installations. Unmanaged and undetected two-way power flows can back feed protective equipment, cause service disruptions, distort power quality, and create voltage instability causing negative customer impacts and reducing reliability.

Q. How will customers benefit from the Grid Reliability and Resilience Projects?

A. The Grid Reliability and Resilience Projects will result in quantifiable benefits in terms of reliability and avoided capital and O&M expense.

In terms of reliability, Tampa Electric forecasts that the combination of these projects and the company’s ongoing SPP activities will reduce SAIDI to approximately 30 minutes per year, reduce MAIFIe to near zero, avoid 30 million customer minutes of interruption, and reduce the CEMI-4 and CEMI-5 metrics to near 0 by 2031.

Improving reliability has significant benefits for customers. The Department of Energy ("DOE") has developed an Interruption Cost Estimator – or ICE calculator – to measure the cost of electric service interruptions to different customer segments. The ICE calculator translates reliability metric improvement into avoided costs for customers based on the economic costs to customers resulting from service interruptions. The ICE calculator model is state-specific and based on the residential and non-residential customer mix. Using the ICE calculator, Tampa Electric estimates that by 2043, the total benefit of the reliability improvements from these projects is a Net Present Value ("NPV") of $2.88 billion. Please see Document 5 of my exhibit entitled: "DOE ICE Calculator Results". Driving down the frequency of outages and enabling more targeted field responses will also reduce the need to deploy utility vehicles to assess reported issues, resulting in cost savings and reduced vehicle emissions.

The Grid Reliability and Resilience Projects are also expected to avoid capital and O&M expenses. As DER proliferate and Tampa Electric develops the capability to manage decentralized circuits through a mix of field devices, substation devices, and management systems, the company forecasts that line losses will substantially decrease. An analysis at one company substation with a high percentage of DER experienced a reduction in line losses of five percent during system peak and as high as 30 percent during off-peak conditions. When scaled across the company's entire system, these avoided line losses result in reduced energy needs. The company calculated the estimated load reduction from the Grid Reliability and Resilience Projects and ran that figure through the company's production cost models. This analysis showed savings in the forms of avoided fuel costs, avoided variable O&M expense, and avoided startup costs. In total, this equals $134.1 million in avoided costs based on the company's current weighted average cost of capital. Please see Document No. 6 of my exhibit entitled: "Line Loss Reduction".

Customers will also benefit from operational savings through automated line restoration and quicker troubleshooting due to automated, self-healing grid technologies installed through the Grid Reliability and Resilience Projects.

Q. When does the company plan to begin the Grid Reliability and Resilience Projects and when does it expect those projects will go into service?

A. The company plans to begin the Grid Reliability and Resiliency Projects in 2024 and conclude in 2023. I provide a schedule in Document No. 7 of my exhibit entitled: "Grid Reliability and Resilience Project Schedule", which shows the company's plans for in service dates and completing the Grid Reliability and Resilience Projects.

Q. What is the Grid Communication Network Project?

A. The Grid Communication Network Project is a component of the Grid Reliability and Resilience Projects. This project is the installation of a private Long Term Evolution cellular network that will allow the company to communicate with its existing field devices and the future field devices planned under the Grid Reliability and Resilience Projects. This project is instrumental in enabling near real-time, two-way communication and control of field devices where we will eliminate the need for field device communication through our radio system that is slow and unsecured. The ability to gather data from field devices and issue remote controls with low latency has a large impact in making the system safer and increasing customer reliability. This project is explained in greater detail in the testimony of Mr. Lukcic.

ELECTRIC DELIVERY AND OUR REQUEST FOR RATE RELIEF

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

A. The Electric Delivery department examines and balances many items including load growth, resilience, reliability, technology improvements, investments across all of Tampa Electric, customer demands and desires, and impacts to customer bills when determining the need for capital investments.

Tampa Electric determines its construction program and capital budget for major T&D facilities through an annual system and capital planning process. This process makes management aware of future capital needs to complete projects necessary to serve customer load, maintain reliability, and ensure resiliency in storms. The system and capital planning process prioritizes capital spending on the right projects to achieve the maximum benefit for customers in addition to balancing out financial requirements for smaller T&D additions, maintenance, restoration, and other T&D needs.

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

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A. The company plans to meet the future requirements of all customers served through its T&D systems using established industry T&D planning requirements, standards, and criteria, and by using standard industry models and tools. These models and criteria ensure that Tampa Electric identifies the most cost-effective projects. Transmission projects are identified and planned through regional models and industry standards, and distribution projects are planned using local models and industry standards.

Tampa Electric's Project Management team is responsible for execution of these projects through engineering and operations and ensuring that project schedules and budgets are maintained through construction until the project is completed.

Q. How much capital did Tampa Electric invest in Electric Delivery during the three-year term of the 2021 Stipulation and Settlement Agreement from 2022 through 2024?

A. For the period 2022 through 2024, the company invested approximately $1.590 billion in capital projects for the Electric Delivery area, of which $994.2 million will be recovered through base rates. The remainder consists of investments that are recovered through the SPP Cost Recovery Clause, AFUDC, and below the line non-utility projects.

Q. How much capital does Tampa Electric expect to invest in Electric Delivery in 2025?

A. In 2025, the company expects to invest approximately $716.0 million in capital projects for the Electric Delivery area, of which $380.8 million will be recovered through base rates. The remainder consists of investments that are recovered through the SPP Cost Recovery Clause, AFUDC, and below the line non-utility projects.

Q. What portion of the total projected capital for the years 2022 through 2025 is comprised of projects described in the direct testimony of Mr. Lukcic?

A. Our total rate base capital for Electric Delivery for the years 2022 through 2025 is projected to be $1.375 billion. Of the $1.375 billion, $357.7 million of the investment is comprised of Operations Technology and Strategy projects described in the direct testimony of Mr. Lukcic.

Q. Please explain which major projects make up the rate base capital total investment in Electric Delivery, why they are needed, and how they will benefit customers.

A. Major projects for 2022 through 2025, and the associated customer benefits are described below.

- The company expects to invest $471.0 million from 2022 through 2024 and $135.9 million in 2025 for blanket capital.
  - o Preventive maintenance activities on the distribution system including wood pole changeouts, underground cable replacements, transformer replacements, switchgear replacements, and capacitor bank maintenance. Replacing these units proactively ensures that the work is done more cost-effectively (scheduled weekday) compared to reactive maintenance that may be done on nights and weekends. It can also reduce customer outages.
  - o Corrective maintenance activities on the distribution system, such as replacing failed overhead and underground equipment and restoration activities following typical storm events.
  - o New lighting installations to satisfy customer requests.
  - o Substation preventive maintenance activities,

including circuit breaker, relay, and switch upgrades, and spare transformer purchases. These investments were identified as part of our Asset Management Program and will significantly reduce the chances of large and sustained outages, improving reliability and service to our customers.

- The company expects to invest $224.9 million from 2022 through 2024 and $71.3 million in 2025 for specific capital, as follows.
  - Distribution system expansion to reliably serve new customers.
  - New transmission lines and upgrading existing transmission facilities to meet capacity and regulatory requirements;
  - Relocating existing T&D facilities located in public rights-of-way in conjunction with road improvement projects;
  - New substation construction and expansion of existing substation facilities to meet the required capacity and to provide reliable electrical service to residential and commercial customers; and
  - New fiber installation and the Grid Communication Network Project.

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- The company expects to invest $69.4 million from 2022 through 2024 and $44.8 million in 2025 to support facilities construction, investments in land, and other non-clause SPP related activities. Please refer to Document No.4 of my exhibit entitled: "Electric Delivery Capital Expense Summary 2022 – 2025".

Q. What major factors caused the projected increase in 2025 capital investment over 2022?

A. There are several major factors that contributed to the increase in total capital spending in Electric Delivery. They include the following items:

1. Contracted labor cost increases.
2. Internal labor cost increases.
3. Material cost increases.
4. Customer growth.
5. Greater demand for utility worker labor.

For example, material cost increases for key components have increased substantially. From 2021 to present, the company experienced price increases for the equipment it buys to provide electric service as follows.

- Transformer prices increased 49 percent.
- The price of poles increased 34 percent.

- Outdoor lighting equipment prices increased 25 percent.
- Switchgear prices increased 21 percent.
- Substation equipment prices increased 36 percent.

Q. What steps is the company taking to make sure these projects are completed at the lowest reasonable cost?

A. Tampa Electric utilizes industry standards, specifications, and codes as the basis for system planning, engineering, and design to ensure our project designs are as efficient as possible while maintaining reliability and safety. Additionally, the company continuously tests the market for pricing regarding material and labor. By following the company's Request for Proposal ("RFP") policies, Electric Delivery ensures material and labor rates are fair and competitive and the selected service providers are qualified.

Q. What are Tampa Electric's projected capital investments in 2026 and 2027 for Electric Delivery and what projects are included in this total for the subsequent year adjustments ("SYA")?

A. The Grid Reliability and Resilience Projects, including the Grid Communication Network Project, are included in the company's request for SYA. These are described in the direct testimony of Mr. Lukcic.

Q. Is there 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. One example is the River to South Hillsborough corridor, which was certified under the TLSA and could be used for future 230 kV facilities necessary to reliably serve existing and future load and to meet existing North American Electric Reliability Company ("NERC") Operations and Planning Reliability Standards. Tampa Electric also has several locations, sized from one to two acres, in areas of expected growth for future load-serving substations throughout Hillsborough County. Finally, the company owns property adjacent to the existing Big Bend Power Station at the intersection of Big Bend Road and U.S. 41 that could be used for a future substation, site expansion, or a renewable generation project.

2025 TRANSMISSION AND DISTRIBUTION O&M EXPENSES

Q. How have the Electric Delivery department's T&D operating expenditures changed since its last rate case?

A. The department's transmission expenditures decreased by $1.8 million, or 10 percent, from $18.1 million in the last rate case to $16.3 million in the test year. $1.2 million of the decrease is attributed to rate base expenditures. Distribution expenditures increased by $7.3 million, or 16 percent, from $65.3 million in the last rate case to $72.6 million in the test year. $7.6 million of the increase is attributed to rate base expenditures.

Q. What major factors caused the projected increase in 2025 O&M expenses over 2022?

A. There are several major factors that contributed to the increase in total O&M spending in Electric Delivery:

1. Contracted labor cost increases.
2. Internal labor cost increases.
3. Material cost increases.
4. Increased material lead times leading to higher inventory needs.
5. Customer growth.
6. Greater demand for utility worker labor.
7. Increased focus on restoration speed.
8. Increased focus on reactive tree trimming to benefit reliability and better meet customer expectations.
9. Technology upgrades and process changes within

distribution and transmission control rooms.

10. Staffing for a Renewable Control Center.
11. Staffing for a Diagnostics and Drone Center.
12. Deployment of distribution equipment that improves reliability.
13. Annual software service agreements.

Increased labor rates continue to be a major factor in upward pressure on O&M expenses. For example, the rates of our primary restoration distribution line contractors have gone up 45 percent since 2021. Higher fuel costs and a tight labor market nationwide for skilled line workers has driven up equipment rates and wages resulting in increased costs to Electric Delivery.

Q. What is the forecasted amount for 2025 O&M expense, and is the amount reasonable?

A. Yes. In 2025, the company plans to spend approximately $88.9 million in O&M expenses for the Electric Delivery department, of which $65.7 million is base rate expenditures. The proposed O&M expenses for 2025 are reasonable and support the activities required for system operations and restoration, inspection programs, maintenance of equipment and computer systems, meter

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services, and required compliance activities.

Tampa Electric mitigated the need to increase O&M expenditures through the company’s culture of continuous improvement, which has generated many initiatives and cost control measures that have been implemented since 2021. They helped mitigate cost pressures in several areas, including the higher labor rates and contractor costs, and material inflation due to market conditions, increased demand, and a limited supply of utility workers.

Q. Were any adjustments made to O&M expenses, and if so, how much?

A. Yes. To obtain an “apples to apples” comparison, an adjustment was made for the SPP related activities. We adjusted the test year by $23.2 million and the base year by $216,000. 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 calculations are shown in MFR Schedule C-41.

Q. What is the company’s performance against the O&M benchmark of the company’s T&D functional expenses?

A. MFR Schedule C-41 reports transmission and distribution expenses and benchmarks separately, and each is below the respective benchmark. Transmission O&M expenses budgeted for 2025 are $4.6 million less than the transmission benchmark. Distribution O&M expenses are $13.3 million less than the distribution benchmark. These variances compared to the benchmarks are due to the company's O&M expense reduction measures taken in the T&D areas, as I describe in my testimony.

Q. What steps has the company taken to manage Electric Delivery O&M expenses?

A. Electric Delivery continuously takes action to ensure O&M expenses are tracked and managed. These actions include managing overtime, seeking skilled labor rates through a fair RFP process, and ensuring team members' time is charged appropriately.

Our Asset Management Program has also 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.

Tampa Electric's technology use also helped control O&M costs. For example, our installation of circuit reclosers not only minimizes total customers out during an outage, but also reduces the time it takes troubleshooters to patrol the circuit to find the damage. Control room technology, like our ADMS system, helps identify outage causes and helps troubleshooters respond more quickly. Since 2013, our customer count has gone up by over 150,000 customers, but our troubleshooting employee count has remained flat, mostly due to the efficient use of technology on our distribution grid allowing for faster troubleshooting.

Tampa Electric has also invested in the replacement of all streetlights and area lights with smart LED technology throughout our service areas. This innovative technology provides a higher-quality light and lasts longer than traditional streetlights, reducing needed maintenance. We have sent 85 percent fewer trucks to repair lighting since the start of the LED conversion, which saves labor and fuel costs.

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 safety initiatives are reflected in T&D O&M expenses for the 2025 test year and why are those initiatives beneficial for customers?

A. Abiding by the SMS described earlier 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 an SMS, the company is not only promoting the safety of its team members, but also its customers and the public.

Q. What was the employee count for Electric Delivery in 2022 and 2023?

A. There were 1,013 team members within the Electric Delivery department in 2022 and 1,028 in 2023.

Q. How many employees are projected in the 2025 test year for the Electric Delivery department?

A. The Electric Delivery department expects to employ 1,081 team members in 2025.

Q. What factors are causing the need to add personnel in the Electric Delivery area?

A. The Electric Delivery team has the largest increase in team members among all areas within the company moving from 197 employees in 2022 to 243 in the test year. These additional employees are needed to complete implementation of Grid Reliability and Resilience Projects and new technologies to further integrate DER, improve restoration times, and collect data from field devices, as mentioned elsewhere in this testimony and as explained in the testimony of Mr. Lukcic.

The balance of new employees is comprised of craft labor and support staff that support operational functions within Electric Delivery, primarily positions within the Energy

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Control Center, Substation, Transmission and Distribution operations.

Q. What metrics did your team use to identify the need for additional employees, contractors, service providers, when to add them, and how many to add?

A. Tampa Electric looks at several factors when considering adding incremental employees to the business. Project growth and changes in operational practices are evaluated to increase or decrease employee count. In certain areas, employee count is increased to moderate overtime and manage safety in the field. Anticipated attrition and the average time to replace employees is also considered when adding employees. Lastly, peaks and valleys in work that are transient are assessed and generally managed with contractors. Tampa Electric evaluated these factors in determining the need to add the employee count I described earlier in my testimony.

SUMMARY

Q. Please summarize your direct testimony.

A. Tampa Electric forecasts that it will invest $380.8 million in Electric Delivery capital and incur $65.7 million in

Electric Delivery O&M expenses for the 2025 test year.

Electric Delivery's capital budget includes investments for the transmission, distribution, and substation expansion and upgrades needed to support customer growth, maintain system reliability, resiliency, replace aging infrastructure, improve our customers' experience, and meet governmental and regulatory requirements. Our 2025 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 historical cost control measures and practices have resulted in O&M spending below the benchmark despite increased interest rates, inflationary material and equipment rates, and increasing wage rates.

Tampa Electric has significantly improved its system reliability since the company's last base rate case. The company's reliability improvements can be attributed in part to the company's robust Asset Management Program and by putting the right systems and personnel in place to minimize outage times when outages do occur.

The company's Grid Reliability and Resilience efforts described in my direct testimony are reasonable and prudent and are necessary to meet the future demands of our customers and to keep pace with electric industry changes. All these projects will provide real benefits to our customers.

Overall, Tampa Electric's proposed T&D capital and O&M budgets for 2025 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 rebuttal testimony of Chip Whitworth was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240026-EI

PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

REBUTTAL TESTIMONY AND EXHIBIT
OF
CHIP WHITWORTH

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
FILED: 07/02/2024

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

CHIP WHITWORTH

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

A. My name is Chip Whitworth. 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 Electric Delivery.

Q. Are you the same Chip Whitworth who filed direct testimony in this proceeding?

A. Yes.

Q. Have your title and duties and responsibilities changed since the company filed your prepared direct testimony on April 2, 2024?

A. No.

Q. What are the purposes of your rebuttal testimony?

A. My rebuttal testimony serves three general purposes.

First, I will address the analysis of Tampa Electric's spare power transformer inventory presented by the Office of Public Counsel's ("OPC") witnesses Kevin Mara and Lane Kollen. I will explain why OPC's analysis is flawed and why it's recommendations should be rejected.

Second, I will address the inaccuracies relating to the company's Storm Protection Plan ("SPP") spending presented in Mr. Mara's direct testimony and illustrate why the Florida Public Service Commission ("Commission") should reject his recommendations regarding that spending.

Finally, I will address Mr. Kollen's recommended reduction in depreciation expense for the company's Feeder Hardening activities.

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes. Rebuttal Exhibit No. CW-2, entitled "Rebuttal Exhibit of Chip Whitworth," was prepared by me or under my direction and supervision. The contents of this rebuttal exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. My rebuttal exhibit consists of the following three documents:

Document No. 1	Historical Transformer Failures
Document No. 2	Historical Transformer Purchases
Document No. 3	Order No. PSC-2020-0224-AS-EI

I. TAMPA ELECTRIC'S SPARE POWER TRANSFORMER INVENTORY IS REASONABLE AND APPROPRIATE

Q. Please explain how Tampa Electric plans for and secures spare power transformer inventory.

A. Tampa Electric has two standardized sizes of medium power (69kV/13kV) transformers: 28 MVA and 37 MVA. Tampa Electric purchases one 28 MVA transformer and three 37 MVA transformers per year. Tampa Electric typically installs 37 MVA transformers in areas of increased system load growth and utilizes 28 MVA transformers in areas where the existing substation footprint does not allow it and load growth is flat. This policy helps to reduce unit costs by $240,000. This approach to maintaining inventory is reasonable and prudent given the rate at which the company replaces transformers, as I will explain below.

Q. On Page 15 of his testimony, Mr. Mara asserts that the company budgeted for "an inordinate amount of transformers." Do you agree with this characterization of the company's plans?

A. No. Tampa Electric has averaged 4.2 medium power transformers (69kV/13kV) transformer failures per year from 2012 through 2023. This is illustrated in Document No. 1 of my rebuttal exhibit. The total actual/estimated spares for years 2021 through 2027 was 29. This equates to 4.8 transformers on average per year that Tampa Electric needs to procure to keep up with future replacements. Additionally, we monitor transformer health and proactively replace transformers that are degrading prior to failure through our Asset Management program, which helps avoid unplanned outages. To illustrate, the company plans to proactively replace three substation transformers under the Asset Management program in 2025.

Q. Please describe the different types of power transformer replacements included in the company's Grid Reliability and Resilience Project and the reasons for those replacements.

A. As explained in Tampa Electric witness David Lukcic's direct testimony, the Grid Reliability and Resilience ("GRR") Projects includes the installation of devices to facilitate automatic fault location, isolation, and system restoration ("FLISR"). FLISR automates system restoration during unplanned outages by facilitating automatic load transfers around the outage elements. This automated FLISR technology will automatically re-route power around faults.

While the company already monitors and replaces degraded transformers, there may also be instances where distribution substation transformer replacements are needed to improve load transfer coordination and provide needed capacity in certain load pockets of our system. Tampa Electric may also need to replace transformers to support new demand as the system load changes over time.

As we deploy FLISR, we expect to find situations where existing transformers need to be replaced due to the new switching scheme and new load growth. These transformers will be replaced as part of the GRR Projects. Tampa Electric does not plan to replace end-of-life transformers through the GRR Projects unless that transformer also needs to be upgraded to accommodate FLISR.

D4-324

Q. On pages 14 and 15 of his testimony, Mr. Mara asserts that the company's plans to upgrade some transformers to accommodate load restoration switching is evidence that the company failed to follow its own planning criteria. Do you agree with this assertion?

A. No. Tampa Electric's planning criteria do not include the upgrade of transformers (or other facilities) to accommodate load under unplanned outage conditions unless relay service is requested and required upgrades are paid for by the customer. The company's plans to upgrade some transformers to accommodate load restoration switching is part of Tampa Electric's FLISR implementation under the GRR Projects which supports outage restoration for all customers. In addition, it is not included in the company's proposed Subsequent Year Adjustments ("SYA").

Q. Also, on page 15, Mr. Mara notes that "including power transformers in SYA is not necessary." Are there any costs associated with power transformer replacements included within the 2026 and 2027 SYA?

A. No. The costs associated with power transformer replacements for the GRR Projects are not included within the SYA.

D4-325

Q. Mr. Mara recommends on page 16 of his testimony that the Commission should exclude four 37 MVA transformers from the company's rate base. What would be the effect of this exclusion?

A. Mr. Mara's recommendation would result in adverse reliability and financial impacts for Tampa Electric's customers. The current lead time to obtain a transformer is approximately two to three years, so ordering four spare transformers annually is needed to serve firm load and provide adequate voltage to customers in the event of a transformer failure. I prepared a table to show the company's actual historical lead times for transformer purchases over the last several years, which is included as Document No. 2 of my rebuttal exhibit.

Disallowing these transformers could also increase costs for customers. The price of these transformers, which the company obtains through competitive bidding, have increased 110 percent since 2020. If Tampa Electric is unable to maintain a healthy spare inventory, it may be required to purchase emergency replacements from other utilities or pay additional manufacturing fees for advanced production slots to shorten lead times, which will increase costs even further. In short, Mr. Mara's proposed disallowance would create additional reliability risk and could also increase costs.

II. TAMPA ELECTRIC'S SPP COSTS IN RATE BASE

Q. Please describe how the company manages the separation of SPP costs and rate base costs.

A. Tampa Electric identifies all SPP costs using the company's accounting system attributes including Funding Projects, Work Orders, and Plant Maintenance Orders or work requests. Each SPP project is assigned a specific code, which clearly differentiates SPP operations and maintenance ("O&M") and SPP capital investments from the company's other O&M and capital investments in the accounting system. These SPP costs are ultimately recovered through the SPP cost recovery clause ("SPPCRC").

Q. On page 16 of his testimony, Mr. Mara states his "understanding is that investments in SPP are recovered through the SPPCRC and are separated from the base rates." Is Mr. Mara's understanding correct?

A. Mr. Mara is correct that investments in SPP projects are recovered separately from traditional distribution capital projects. Certain SPP activities, however, require installing new equipment as well as removing existing assets. The costs associated with removal of some of these assets are charged to base rates. This accounting treatment is required by the "2020 Settlement Agreement," which was signed by OPC and approved by the Commission in Order No. PSC-2020-0224-AS-EI, issued on June 30, 2020, in the company's 2020 SPP docket. A copy of this Order is included as Document No. 3 to my rebuttal exhibit.

Q. What does the 2020 Settlement Agreement state with respect to the cost of removal associated with SPP projects?

A. Paragraph 12 of the 2020 Settlement Agreement states: "For assets being retired and replaced with new assets as part of a program in the company's SPP, the company will not seek to recover the cost of removal net of salvage associated with the related assets to be retired through the SPPCRC." Paragraph 13 similarly requires the company to recover the cost of distribution pole replacements, and the O&M expenses associated with asset transfers related to distribution pole replacements, through base rates and not through the SPPCRC. Tampa Electric witness Jeff Chronister will address this topic from an accounting perspective in his rebuttal testimony.

D4-328

Q. Is Mr. Mara correct that a portion of the company's SPP Feeder Hardening costs are included in base rates?

A. Yes, the SPP Feeder Hardening program requires removal of existing rate base equipment and installation of new equipment. As I previously explained, the 2020 Settlement Agreement requires Tampa Electric to charge the costs of removal to base rates.

Q. On pages 18 and 19 of his testimony, Mr. Mara asserts that he is "waiting on a response to a data request" for certain feeder hardening information for the year 2024. Are you aware of any outstanding discovery owed to OPC related to SPP Feeder Hardening data?

A. No. Mr. Mara references OPC's Seventh Set of Interrogatories No. 121 on pages 18 and 19, but that interrogatory did not request Feeder Hardening program data for 2024. Tampa Electric is not aware of any other discovery request to date that asked for that information. Tampa Electric also received confirmation from OPC on June 24, 2024, that the company has no outstanding unanswered discovery requests from OPC related to SPP Feeder Hardening.

D4-329

Q. On page 19 of his testimony, Mr. Mara asserts that the company's separation of SPP and base rate costs is "not working as intended" or that the company is "purposefully moving dollars from SPP to base rates." Are either of these assertions correct?

A. No. Tampa Electric is properly accounting for cost of removal as required by a Commission-approved 2020 Settlement Agreement that OPC signed.

Q. Do you agree with Mr. Mara's recommendation that $7.97 million of "feeder hardening costs" be shifted from base rates to the SPP?

A. No. For the reasons I previously described, the cost to remove existing rate base assets associated with the SPP Feeder Hardening program should be recovered through base rates.

Q. Is Mr. Mara correct that a portion of the company's SPP Lateral Undergrounding costs are assigned to base rates?

A. Yes. Like the Feeder Hardening activities mentioned above, the SPP Lateral Undergrounding projects require removal of existing rate base equipment and installation of new equipment. The 2020 Settlement Agreement requires the company to recover these costs through base rates.

Q. Do you agree with Mr. Mara's characterization of the company's SPP Lateral Undergrounding program as including "accelerated costs" on page 21 of his testimony?

A. No. Tampa Electric is not completing more miles of underground conversions than it originally planned. However, I do agree that these SPP costs will be reviewed and explained through the separate SPPCRC proceeding.

III. OPC'S PROPOSED CHANGES TO FEEDER HARDENING COSTS IN BASE RATES SHOULD BE REJECTED

Q. On page 5 of his testimony, Mr. Kollen presents a recommended reduction to Tampa Electric's proposed operating income and rate base to remove feeder hardening costs associated with Mr. Mara's recommendations. Do you agree with these adjustments to the company's projected test year budget?

A. No. For the reasons I previously discussed, the costs associated with removing existing rate base equipment during the course of executing the SPP Feeder Hardening and Lateral Undergrounding projects should remain within

Tampa Electric's operating income and rate base and be allowed within the test year budget.

IV. SUMMARY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addressed statements made by witnesses Mara and Kollen regarding Tampa Electric's management of spare distribution transformers and cost allocation between base rates and SPP. I demonstrated that Tampa Electric is prudently managing spare transformer inventory to ensure system reliability. I also explained that Tampa Electric continues to manage costs appropriately to separate traditional distribution work and SPP work in accordance with previous Commission Orders. The recommended adjustments of witnesses Mara and Kollen are not appropriate and should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BY MR. MEANS:
Q Mr. Whitworth, did you also prepare a cause to be filed with your direct testimony an exhibit marked CW-1, consisting of eight documents?
A I did.
Q Did you also prepare a cause to be filed with your rebuttal testimony an exhibit marked CW-2, consisting of three documents?
A I did.
MR. MEANS: Mr. Chairman, Tampa Electric would note for the record that Exhibits C-1 and C-2 have been identified on the Comprehensive Exhibit List as Exhibits 21 and 145.
CHAIRMAN LA ROSA: Okay.
BY MR. MEANS:
Q Mr. Whitworth, did you prepare a summary of your direct and rebuttal testimony?
A I did.
Q Will you please give that summary?
A Sure. Good morning, Commissioners.
My direct testimony describes the company's transmission and distribution system; how our system has grown and changed since the company's last base rate case; how our customers have benefited from improved blue sky and extreme weather reliability; and why our

capital investments in the T&D system since the last rate case were necessary and prudent.

My direct testimony explains the capital and O&M investments in our T&D system for transmission, distribution, substation expansion and upgrades that are needed to support customer growth, maintain and improve system reliability, improve grid resiliency, replace aging infrastructure, improve our customers' experience, and meet our governmental and regulatory commitments.

Lastly, my direct testimony describes how Tampa Electric's proposed T&D capital and O&M budgets for 2025 represent a strategic and balanced approach that will provide a modern grid to be our consumers' increasing expectations, adapt growing demand, and ensure a grid that will be safe, resilient, secure and reliable for many years to come.

My rebuttal testimony addresses two main issues raised by the Office of Public Counsel's testimony related to the company's spare medium power transformer inventory and accounting for SPP work.

First, my rebuttal testimony explains the company's reasonable prudent process for maintaining transformer inventory. Tampa Electric currently has four spare medium power transformers in stock. And the Office of Public Counsel has requested the company reduce the median power transformer inventory level by four.

I recommend that the Commission make no adjustment to our transformer inventory levels. Since lead times for medium power transformers are approximately a year-and-a-half to two years, they are an essential piece of equipment to serve our customers, and needed to keep up with energy demand and customer growth.

Second, my rebuttal testimony explains how OPC's recommended reclassification of certain feeder hardening costs from base rates to the SPP recovery clause is inconsistent with the Commission's order, when Tampa Electric's 2020 SPP Settlement Agreement approved. That agreement, which OPC signed, requires Tampa Electric to charge the cost of removal for assets that are being retired as part of an SPP project to the accumulated depreciation in rate base used to set base rates.

I recommend that the Commission make no adjustments to the feeder hardening cost or removal expenses since those costs were charged properly under the 2022 SPP Settlement Agreement.

This concludes my summary. Thank you.

MR. MEANS: We tender the witness for

cross-examination.

CHAIRMAN LA ROSA: Thank you.

OPC, you are recognized when you are ready.

MS. CHRISTENSEN: Good morning, Commissioners.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning --

A Good morning.

Q -- Mr. Whitworth.

Mr. Whitworth, can I have you just take a look at page two of the testimony that's up there?

And in your direct, you say that your duties include advanced metering infrastructure, advanced distribution management systems, line clearing activities and fleet equipment; is that correct?

A That's correct.

Q And are you aware of the filing that your company made on August 22nd, 2024, where TECO revised portions of the GRR program that's now included in this request?

A Could you repeat the questions, please?

Q Sure.

Are you aware of the August 22nd filing that was made to revise the request?

A Yes, I am.

Q Okay. And are you aware that in that filing, one of the things that they revised were the number of programs that were included in the GRR?

A Yes, I am aware of that.

Q Okay. Can you tell me how many programs from the original 40 programs that you discuss in your testimony on page 22 have been removed?

A That question is better suited for witness David Lukcic.

Q Lukcic?

A Yes.

Q Okay. Let me ask you this question: Would I be correct that removing these programs from this request does not mean that these projects will not be done?

A That's correct.

Q And looking at page 22 of your testimony -- and let me know when you get there -- lines 15 or 17, I believe is what I was referring to.

In that portion of your testimony, you say: It is TECO's goal to complete all of the projects by 2030. But you would agree that that completion date is not a firm date?

A Our intent is to complete the entire set of our GRR projects by 2030. I would also like to note

that we are not asking the Commission to improve the
entire set of the GRR projects through this rate case.
We are only asking you to improve a subset of those that
are in 2025 and the subsequent year ask.

Q Am I to assume from the fact that you responded you would like to complete them by 2030, that you agree that with my questions, that it's not a firm date?

A We intend to complete it by 2030, and I would defer to witness David Lukcic for the specifics of in-service times and dates in and around the GRR project.

Q Okay. On the bottom of 2022, on the page -- this page of your testimony, you claim -- your claim is that aggregating these projects results in more efficient capital spend and enhancement functionality, not that all these 40 projects cannot be done individually; is that correct?

A That's correct.

Q Moving on to page 24 of this portion of your testimony, you say that the GRR projects are necessary to replace obsolete systems and equipment that have reached the end of their life, correct?

A That's correct. That is one component of the GRR projects.

Q You would agree that replacing old obsolete equipment is normal activities for a utility, right?

A In certain circumstances, it is. In other circumstances, when you can replace these assets in a coordinated fashion, there is a way that the company can execute these projects and save the customers further capital by the efficiency of how these are executed and rolled out. And witness David Lukcic has a great deal of detail on those execution plans.

Q So you agree that replacing old obsolete equipment is normal activities, right?

MR. MEANS: Objection. Asked and answered.

CHAIRMAN LA ROSA: It has been asked. You did --

MS. CHRISTENSEN: I know I asked it. I just didn't get a yes or no answer, but if I could ask that the witness be directed to give me a yes or no answer and then a brief explanation, I would --

CHAIRMAN LA ROSA: Oh, so I am going to allow the question to be asked, but I will -- if the witness can answer the question, I will allow the question.

BY MS. CHRISTENSEN:

Q And I think you affirmatively agreed that it is normal activities to replace old obsolete equipment,

yes?

A I said in certain circumstances it is.

Q Okay. You then say in your testimony that investments are to improve reliability, access to data and adapt to changes, correct?

A What page and line are you on, please?

Q I am on page 22 -- or, I am sorry, 24. And I believe we are looking at your answer which starts at line four.

A Excuse me? Which line?

Q Line four. If you need to read through that answer, that's fine.

A Okay. Thank you.

Q So would you agree that your testimony, you say, investments are to improve reliability, access data and adapt to changes, correct?

A That's correct.

Q Would you agree that TECO routinely looks for ways to improve its systems functions?

A We do.

Q Okay. And let's go to page 29 of your testimony. And looking at lines one and two on that page, it says: The company plans to begin the Grid Reliability and Resiliency Projects in 2024 and conclude in 2023. Did you mean to say 2030 in that portion of

your testimony?

A   Yes. That should say 2030.

Q   Okay. And would you agree that existing field devices communicate through your SCADA radio network currently?

A   They do.

Q   And would you agree that the current radio SCADA system was installed in 1990 --

A   That's correct.

Q   -- and that it -- oh, I'm sorry.

A   That's correct.

Q   And that the SCADA system needs replacing?

A   That's correct.

Q   Okay. Looking at your exhibit to your testimony, document 7 -- and give it a minute to come up here.

Okay. And this is an exhibit that shows the GRR project as proposed, correct?

A   No, it does not. This is just a general graph that shows large buckets of the project and a general description of the project and timeline, but does not depict any sort of in-service dates.

Q   Okay. So it's a general indication of the projects and the timeline, but not a specific in-service date, correct?

A Correct.

Q Okay. And part of this talks about the new communication platform that is the PLTE Spectrum, is that correct?

A It does mention that, yes.

Q Okay. And that's the purple line, right?

A Yes. Correct?

Q Okay. And the PLTE Spectrum project, that's protected to go into service in 2026. Is that still correct?

A That's my understanding, but witness David Lukcic has the specifics on the private LTE project and all of the GRR projects.

Q Okay. Then let me ask you the questions, and to the extent you know, if you can answer them.

And looking at the blue field devices, these are items that will communicate via the PLTE Spectrum system, correct?

A That's correct.

Q And your plan is to modify to -- your plan is to modify existing capacitors already out in the field to communicate through the PT -- or PLTE system, correct?

A Yes. We plan to -- we have to modify existing equipment more so than capacitor banks. There is also other equipment we might have to modify. And certainly what we call new will have the capability to communicate through the cellular network. And, again, witness David Lukcic can provide all of the details in and around how that communications network will interact with these field devices.

Q Okay. And you will also replace older automatic lateral switches and modify the newer ALS switches to connect via the PLTE Spectrum system, correct? That's the plan?

A If necessary, yes.

Q Okay. And starting on page 36 of your testimony. And when we get there, we are going to be looking at -- starting at line 19, and then through the top of the next page.

Okay. Your -- you mention the projects included in the subsequent year adjustment in this section of your testimony, correct?

A I am sorry, which page and which line?

Q Looking at page 36, starting at line 19. You have a question regarding the projected capital investments in '26 and '27 that were going to be proposed to be put into the subsequent year adjustments. Do you see that?

A I do.

Q Okay. And that was my question, is this is the portion of your testimony starting here, and then going on to the top of the next page, where you discuss the projects that will be included in the '26 and '27 projected -- or the subsequent year adjustments, correct?

A No, that's not correct. My answer says that the subsequent year adjustments will be explained witness David Lukcic.

Q Okay. And then you -- well, to a certain extent, you do discuss the GRR projects, correct, because you included document 7?

A Yes. I discuss the GRR projects in a strategic overall level and view and perspective of what we intend to achieve from that. Specific details of how we execute that and the in-service dates for those are with witness David Lukcic.

Q Okay. Well, let's go back to document 7.

Okay. And you have green boxes with a line for breaker replacements and digital relays. You would agree that you replacement breakers -- that you replace breakers when they are old and obsolete, correct?

A Not necessarily when they are, you know, not necessarily old and obsolete, but certainly when they become non-functional and non-serviceable --

Q Okay.

A -- we would make an attempt to do that. This is referencing relays that are not compatible with the cellular communication technology and our communication plans for our modernized grid.

Q Let me ask you this: When do you replace older breakers, for whatever the reason, and put them into service in between rate cases, that would become part of rate base that's recovered in the next rate case, would that be correct, to your knowledge?

A Yes.

Q Okay. In looking at the green line for power transformer replacement, you would agree that you upgrade or build out transformers relative to TECO's system planning and customer growth and demand, correct?

A I would. We do our overhead distribution planning according to a steady state criteria.

Q Okay. And you would also agree that in the past, when you normally replace transformers to customer growth and demand and put it into service between rate cases, it becomes part of rate case that is then recovered in the next base rate case, correct?

A That's correct.

Q Let me take you to OPC Exhibit 145, which I believe is F2.2-7210.

Are you familiar with this document?

A I am.

Q Okay. And can we have you look at page three of this document? And let me know when you get there.

A I am there.

Q Okay. Wonderful.

And if you look at the bottom of that document, you see the Project Risk Assessment header?

A I do.

Q Okay. You would agree that the third bullet down talks about the risk of material shortages, correct?

A It does.

Q And then if you look further down, about the fifth bullet, it says the program benefits are not achieved on the specific timelines is another risk you identified?

A That's correct.

Q And the additional risk that you identified is the pace of change exceeds the organization's ability to adapt. And you called that change fatigue, correct?

A Correct.

Q Another risk you identified related to the GRR programs is the cost changing unexpectedly over time, correct?

A That's correct. And what I really like about this list is it shows the company's forethought in understanding the risk before we enter a capital project like this. Before we even started, we have mapped it out. We communicated it to our leaders. We communicated it to our staff. And we are mapping out and understanding what mitigation plans do we put in place to avoid these risks. We are thinking about it way ahead of time.

Q Okay. And then --

A And I think this is a testament for of how we achieve success?

Q And finally, one of the other risks that you identified was that technology and standards change over the program life, among others risk, correct?

A Correct.

Q Okay. If I can have you look back on page 24 of your direct testimony. And specifically, I am looking at line 10 and -- 10 through 14.

You mention an always-on experience. Do you see that?

A I do.

Q Are you warranting that customers will never lose service if the GRRP is fully implemented?

A I am not.

Q Okay. Am I correct, that you believe the GRR projects are giving the distribution system a brain, whereas, the SPP is the physical assets that are being replaced?

A That's correct.

Q And you would agree that there is a FLISR component to the SPP, i.e., mechanical devices that are going out in the field, correct?

A That's correct. The mechanical devices as part of FLISR are installed via SPP since the crews are there. They are mobilized. They are already performing the work. It's just a matter of efficiency to go ahead and have them install that hardware. And then GRR will come behind that, give it a brain and provide the communication and coordination.

Q And you can you tell me what FLISR stands for?

A Fault Location Isolation and System Restoration.

Q Okay. And would you agree that the FLISR would be an overall system concept that includes field devices, a communication network and software to coordinate it?

A Yes, I would.

Q And you will mainly rely on Alabama Power as your example of a utility development of a private LTE

communication network and FLISR technology, is that correct?

A No, that is incorrect. We have a team of people, and a staff of people who evaluated this technology. At many utilities, it's a known technology, a proven technology that's been installed throughout the U.S., and Alabama is one example of an IOU that's nearby that we have had discussions with. But by no mean is that sole example. There are many examples across the country of this technology.

Q But that's the one that you are most familiar with, and the one that you actually had the most familiarity with, correct?

A That would be the company that I went to visit --

Q Okay.

A -- to see how they deployed FLISR.

Q And isn't it true the affiliate company in Canada, Nova Scotia Power, does not have a GRR program or a FLISR type program or private network to your knowledge?

A Not to my knowledge.

Q And TECO is seeking PSC approval for the, in this proceeding, that the GRRP is prudent, correct?

A We are only seeking a portion of the GRR project in its entirety, and David Lukcic can speak to that during his --

Q Okay. So then you would agree that if the GRR components only about 400 to 500 million that will not go into -- will not go into service until after 2027, TECO will come back in the future and ask for PSC authorization to recover those costs later?

A That's correct. Whatever is not allowed in '25 and the subsequent year ask, that will be for another rate case.

Q Okay. So you are not seeking prudence of the continual program beyond what you are asking for through 2027, correct?

A Correct.

Q Okay.

MS. CHRISTENSEN: I have no further questions. Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

Florida Rising/LULAC.

MS. LOCHAN: Thank you so much, Chairman.

EXAMINATION

BY MS. LOCHAN:

Q Good after -- I believe it's afternoon now. I think I can safely say that. Good afternoon, Mr. Whitworth.

A Good morning, yeah -- or afternoon, everyone.
Q Almost lunchtime.
Nice seeing you again. I think we met during the depositions.
I just have a few questions. I am going to try not to be repetitive with the questions that Ms. Christensen just asked, but I will direct you to your -- actually, just speaking generally about your testimony, you did look at sort of long-term trends of the grid reliability project?
A We did. Yes.
Q Thank you.
I will direct you to -- this is staff Exhibit 21, master number E4022. And if we can rotate it. Perfect.
Just scrolling down to where there are the key bullet points, or key observations. The first bullet point does state that TECO has maintained second place in the state in the last few years, with minimal reliability engineering and proactive preventative maintenance programs, correct?
A That's correct.
Q Thank you so much.
Now, I would like to direct you to your testimony, particularly -- this is master page C6-938.

Great. If we can scroll down to lines 13 and -- yeah, to line 13 -- sorry. C6-938 -- sorry -- oh, 398. Sorry, my own device is loading.

Generally speaking, the reliability project is purported to benefit customers, correct?

A That's correct.

Q Thank you.

If we can pull up FLL-265, which is master number F3.5-24488. And these are the, I feel like I am going to say this incorrectly, but MAIFI -- the MAIFI numbers regarding the reliability improvement project.

A It looks like, based on the title, this was the data that was used for the ICE calculator.

Q Thank you so much.

And if you look under column B, line three, this shows that residential customers have a total benefit of six percent?

A That's correct.

Q And 94 percent would be going towards other customers?

A Small C&I, Medium and Large C&I.

Q Mr. Whitworth, would you agree that residential customers are the vast majority of TECO's customers?

A I would say we have a higher number of residential customers, yes, than commercial/industrial customers.

Q Okay. Thank you.

I am now going to pull up FLL-266, which is master number F3.5-24492.

And once again the -- I might say this correctly, but this shows these SIADI (ph) benefits -- SAIDI benefits?

A I don't -- the improvements, they look more like customer minutes improvements more so than SAIDI improvements.

Q Will the title of the document jog your memory on the top, where it has the Bates stamps number?

A It does. It says, ADI SAIDI ICE benefits, so I'm -- so, yeah, just not -- just not how I am used to seeing that data, so...

Q Got it. But if I could direct you to the third line. This shows that residential customers have a total benefit of five percent, correct?

A I do not see five percent on this page.

Q Are you on the -- if you scroll up?

A Okay. Yep. Yes, five percent.

Q All right. Thank you so much.

I believe those are all my questions, Mr. Whitworth. Thank you.

CHAIRMAN LA ROSA: Thank you.

FIPUG.

MR. MOYLE: Thank you, Mr. Chairman, just a couple of quick questions.

EXAMINATION

BY MR. MOYLE:

Q Good morning.

A Good morning.

Q I had asked a question about the smart grid. I am interested in learning a little bit more about that, and in particular, when do you believe you will have the ability for the grid to notify the company of an outage as compared to customers having to call and say, hey, I have an outage, can you come fix it? It seems like there is evidence that suggests that's a pretty significant time piece, to have the customer call, and then that message get translated down. So I am just looking for maybe a narrative answer with respect to the timing of that and, generally speaking, how it would work.

A Sure. I did hear Witness Sparkman's testimony yesterday, so I am familiar with the question. And we do currently, today, have the ability to know when an entire circuit is out, which translates to customer outage as well. We also have AMI data that comes through a system that aggregates, that shows, hey, there are -- these meters are out, there may be a problem here. That, coupled with a call from a customer, allows us to dispatch the troubleshooters to the appropriate location. So we are not totally blind, but it's not as specific as we want to get.

My expectation, and something witness David Lukcic can speak to, is that by 2030, we expect to have that technology to be able to pinpoint precisely where navigation is, and have the ability to dispatch troubleshooters and repair workers to a very specific location to expedite those repairs.

Q Just to follow up on the dispatch piece. Is that also projected to be taking place at some future point in time? You had referenced 2030, but that would be done without human beings being involved, that it would just send a message and go to a message, and no passing along messages through humans?

A As we begin to deploy FLISR technology -- that's that acronym we talked about earlier, Fault Location Isolation and System Restoration -- as we begin to deploy that through this process, that's precisely what will happen. The technology will be able to detect an anomaly on the grid, or an outage, automatically restore as many customers as possible prior to human intervention; and also pinpointing where the fault location is, where we could roll resources directly to that location for repair, so...

Q And with respect to how you are rolling this system out, are you prioritizing circuits that, say, have MacDill Air Force Base on it, or have Tampa General Hospital, airport, in a way so that your more critical infrastructure is going to be plugged in first?

A We currently do have customer reliability programs for folks like the airport, for folks like TGH hospital, and those types of things. Even a Walmart distribution center, big food distribution center is on there where we track those assets very closely, and the performance of those already, and we have certain alarms and substation alarms that come to the control room on those particular -- that particular infrastructure.

As we roll out FLISR through GRR, it's going to follow the timeline of our cellular network. And as those towers go in, we will then deploy the field devices and such that all that tower construction, and start to bring that technology into the control room.

Q Okay. And just briefly on the cell network, is that going to be a cell network that is exclusive to TECO's use, or will it be a cell network that third-parties will also be able to use, or something

else?

A Yeah. It is a private cellular network, and it was evaluated for many reasons. And how we landed on that, and one of the biggest drivers, is that that is just more secure. It's a much more secure way of communication between our devices and data transfer.

MR. MOYLE: Those are all my questions I have. Thanks.

CHAIRMAN LA ROSA: Thank you.

FEA.

CAPTAIN GEORGE: No questions, Chairman.

CHAIRMAN LA ROSA: Thank you.

Sierra Club.

MR. SHRINATH: No questions, Mr. Chairman.

CHAIRMAN LA ROSA: Thank you.

FRF.

MR. WRIGHT: Thank you, Mr. Chair. I just have a very few follow-up questions to his discussion with Ms. Christensen.

EXAMINATION

BY MR. WRIGHT:

Q Good morning, Mr. Whitworth. How are you doing?

A Wonderful. Good morning.

Q My name is Schef Wright. I represent the

Florida Retail Federation, and I just wanted to follow up on a response you gave to a question from Ms. Christensen.

She asked you whether it was normal to replace old and obsolete equipment, and you said, under certain circumstances. My question is: When is it not normal to replace old or obsolete equipment?

A So what I meant by that is we have to -- we have to do that obsolete equipment replacement in a organized and timely fashion. It's something that has to be coordinated. Typically that equipment is integrated with other pieces of equipment in and around the system. And as soon as it becomes obsolete, we would have to coordinate that.

The other thing is that oftentimes, through proper asset management programs and proper health analysis, we can also work with that piece of equipment for a duration of time, maximizing our capital investment, which also maximizes the customers' investment as well. So we get full use of that piece of equipment.

Q So I think I understood part of your follow-on discussion to indicate that you might replace the function of a piece of equipment with better equipment, or equipment that would do more than the old obsolete

equipment did, is that kind of what you are getting at?

A It is. With respect to GRR and those projects, that's correct?

Q Okay. Thanks very much. That's all I had?

A Okay.

CHAIRMAN LA ROSA: Great. Thank you.

Walmart.

MS. EATON: We have no cross. Thank you.

CHAIRMAN LA ROSA: Staff.

MR. SPARKS: Staff has no questions. Thank you.

CHAIRMAN LA ROSA: Commissioners, questions?

Seeing none, TECO, I give it back to you for redirect.

MR. MEANS: Thank you, Mr. Chairman.

FURTHER EXAMINATION

BY MR. MEANS:

Q Mr. Whitworth, I want to ask you real quickly about this document, FLL-266, that's pulled up here.

And do you see at the top there, where it says, reliability improvement?

A I do.

Q Is the only benefit of the GRR project going to be reliability improvement?

A It will not. There are any benefits in addition to reliability. Reliability is just one of the things that we balance when we consider what's happening with the grid, and how the grid is changing.

In fact, I would add one of the largest benefits to GRR is being able to detect two-way power flows. We currently have 25,000 customers with rooftop solar. In 2030, we expect to have around 75,000 customers with rooftop solar. That's around 770 megawatts of connected nameplate and capacity.

This will result in two-way power flows on our system, and this is important for three main reasons:

No. 1, safety. Safety of our workers. Our workers need to understand the direction of power flow so they can properly isolate the system and remove the hazardous energy to go to work.

No. 2, the equipment we install out there needs to be technically capable to handle two-way power flows.

No. 3, to the extent we can understand the contribution of renewable energies that are being injected on our grid, we can back down traditional fossil fuels and reduce line losses, which saves the customer money through fuel losses -- or fuel savings.

So those are three main reasons. There is many other reasons, from a security perspective, an obsolescence perspective, which we have talked a lot about, and also improving our customer experiences and different data offerings that we will be able to have access to.

Q Will any of those benefits accrue to residential customers?

A Yes, they will.

MR. MEANS: No further questions.

CHAIRMAN LA ROSA: Great. Thank you.

Okay. So let's now move exhibits into the record.

MR. MEANS: Tampa Electric moves Exhibits 21 and 145 into the record.

CHAIRMAN LA ROSA: Okay. Are there objections? Seeing none, show them as entered into the record.

(Whereupon, Exhibit Nos. 21 & 145 were received into evidence.)

CHAIRMAN LA ROSA: OPC?

MS. CHRISTENSEN: OPC would move 370 into the record if it has not already been admitted.

CHAIRMAN LA ROSA: Okay. Is there objection?

MR. MEANS: No objection.

CHAIRMAN LA ROSA: Seeing none, then show that entered into the record.

(Whereupon, Exhibit No. 370 was received into evidence.)

CHAIRMAN LA ROSA: Anybody else?

MS. LOCHAN: And Florida Rising and LULAC would like to move Exhibits 725 and 726 into the record.

CHAIRMAN LA ROSA: 725 and 726, any objection?

MR. MEANS: No objection.

CHAIRMAN LA ROSA: No objection, show that entered into the record.

(Whereupon, Exhibit Nos. 725-726 were received into evidence.)

CHAIRMAN LA ROSA: Any other exhibits?

Seeing none, Mr. Whitworth, you are -- I almost said you are recognized. I think you have done enough of answering questions, but you are excused, sir. Thank you very much.

THE WITNESS: All right. Thank you. Thank you so much.

(Witness excused.)

CHAIRMAN LA ROSA: All right. TECO, I will throw it back to you to introduce your next witness and we will see how far we can get with him before lunch.

MR. MEANS: Thank you, Mr. Chairman. Tampa

Electric calls David Lukcic.

MR. WAHLEN: Mr. Chair, while we are on a break, would it be all right if I said, congratulations for making this document system work, and the lawyers working it, and the people working it? It's actually turning out to be fairly cool. I don't want to jinx it or anything, but --

CHAIRMAN LA ROSA: I had similar thoughts, but --

MR. WAHLEN: So if fails this afternoon, you can blame me, but I just wanted to acknowledge all the hard work and effort. It doesn't look like it's on its way, and appreciate that.

CHAIRMAN LA ROSA: Yeah. Thank you. No, it's certainly from, at least my perspective being up here, makes that following along a little bit easier, especially when doing multiple things, so yeah, I think we are good. Okay, and we won't look your direction if you do jinx. Hopefully you don't.

Mr. Lukcic, sorry I didn't get to you before you sat down. Do you mind standing up just very quickly? I do not believe you have been administered the oath. Please raise your right hand.

Whereupon,

DAVID LUKCIC

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

THE WITNESS: I do.

CHAIRMAN LA ROSA: Excellent. Thank you.

THE WITNESS: Thank you.

EXAMINATION

BY MR. MEANS:

Q Good morning, Mr. Lukcic.

A Yep. Good morning.

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

A Yes. David Lukcic.

Q And you were just sworn, correct?

A Yes, I was.

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

A Current employer is Tampa Electric Company. Business address is 702 North Franklin Street, Tampa, Florida.

Q Did you prepare and cause to be filed in this docket, on April 2nd, 2024, prepared direct testimony consisting of 61 pages?

A Yes, I did.

Q Did you prepare and cause to be filed in this docket, on July 2nd, 2024, prepared rebuttal testimony consisting of 20 pages?

A Yes, I did.

Q Do you have any additions or corrections to your prepared direct or rebuttal testimony?

A I do not.

Q Mr. Lukcic, are you familiar with the August 22nd filing Tampa Electric made to change the company's revenue requirement?

A Yes, I am.

Q Do you have any changes to your testimony associated with that filing?

A I do. Yes.

On August 22nd, Tampa Electric filed a change to the company's revenue requirements to remove the cost of the project referred to as Line Sensor Software and the Distribution Planning Software for the company's SYA. This would change my direct and rebuttal testimony in several places. Instead of going through that page by page, I just want to note on the record that all discussion of these two projects in my testimony no longer applies.

Q Thank you.

And other than those changes, if I were to ask you the questions contained in your prepared direct and rebuttal testimony today, would your answers be the same?

A They would.

MR. MEANS: Mr. Chairman, Tampa Electric requests that the prepared direct and rebuttal testimony of Mr. Lukcic be inserted to the record as though read.

CHAIRMAN LA ROSA: Okay.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID LUKCIC

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

A. My name is David Lukcic. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or the "company") as Senior Director Operational Technology & Strategy.

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

A. As Senior Director Operational Technology & Strategy, I report to the Vice President of Electric Delivery. My areas of oversight include Data Analytics, Distributed Intelligence, Asset Management, Grid Modernization, Operations Technologies, and Data and Technology Governance. I am responsible for several operations areas within the company, including Telecommunications, Meter Operations, Lighting Operations, and Advanced Metering Infrastructure Operations. I lead a total of approximately 280 team members.

C7-414

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

A. Yes, I have testified or filed testimony in several dockets, including testimony for Tampa Electric in Docket No. 20120234-EI, Tampa Electric's Petition to determine the need for the Polk 2-5 combined cycle conversion.

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

A. I graduated from the University of South Florida with a bachelor's degree in electrical engineering and an executive master's degree in business administration.

I have more than 25 years of experience in the energy industry. Prior to becoming the Senior Director of Operational Technology and Strategy in 2022, I led the Automated Metering Infrastructure ("AMI") deployment and built the AMI operational organization. I have worked in both Energy Supply and Electric Delivery and at all three of the company's generation stations, Big Bend, Bayside, and Polk Power Station. My previous roles within the company include meter operations, environmental, capital projects, distribution engineering, and standards.

C7-415

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to (1) describe the company's Operations Technology & Strategy ("OT&S") department and the operations technology resources and applications Tampa Electric uses to operate its electric system and provide an outstanding customer experience; (2) explain the progress made in the OT&S area since the company's last base rate case; (3) summarize the OT&S department's plans for the future; (4) explain the company's OT&S capital investments and operations and maintenance ("O&M") expense; and (5) describe the Grid Reliability & Resilience Projects that will be going in service as part of Tampa Electric's subsequent year adjustments ("SYA") for 2026 and 2027.

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

A. Yes. Exhibit No. DL-1, entitled "Exhibit of David Lukcic," 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 David Lukcic

Document No. 2 Operation Technology Capital Expense Summary 2022-2025

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 contents of my MFR schedules were derived from the business records of the company and are true and correct to the best of my information and belief.

OVERVIEW OF THE OT&S DEPARTMENT

Q. What is operations technology and how does it differ from information technology?

A. Operations Technology ("OT") consists of hardware, software, and field assets used to monitor and control the company's electric generation units, distribution equipment, meters, and lighting. This technology helps ensure that the company continues to provide reliable and affordable service to our customers. Tampa Electric uses OT to improve efficiency and reliability, to educate customers, and to enable more customer choice. OT is distinct from Information Technology ("IT") as OT focuses on real time functionalities such as control systems, Supervisory Control and Data Acquisitions ("SCADA") systems, and automation tools for the functions previously listed. The company's IT department supports the OT&S department by managing network infrastructure, cybersecurity, data management, and integration between systems. The IT department also provides the necessary expertise to ensure the reliability, security, and efficiency of operational processes.

Q. Please describe the company's OT&S department.

A. The OT&S department manages and maintains the operational technology infrastructure essential for the delivery and management of company services. We provide a range of OT services for Tampa Electric, including Strategic Leadership; Data and Technology Analytics and Governance; Project Management and Operations; Grid Modernization Strategy; Network Operations; Asset Management; and OT Operations.

Additionally, the OT&S department specifically supports the activities of the company's Energy Supply, Electric Delivery, and Customer Experience departments by providing technology, services, and advice regarding best practices.

Q. Does Tampa Electric's OT&S department provide OT services to the company's affiliates?

A. No.

Q. Does Emera Inc. ("Emera") or any other Emera company provide OT services to Tampa Electric?

A. No.

OT APPLICATIONS THAT SUPPORT THE CUSTOMER EXPERIENCE, ELECTRIC DELIVERY, AND ENERGY SUPPLY DEPARTMENTS

Q. What major OT applications support customer experience activities?

A. The OT&S department oversees and administers several OT systems that support the company's Customer Experience department's initiatives. These include AMI, Data Analytics Platform ("DAP"), Distributed Intelligence ("DI"), Artificial Intelligence and Machine Learning

("AIML"), and Street Light Vision ("SLV").

Q. Please describe the applications listed above and how they support the Customer Experience department.

A. Tampa Electric's AMI system includes advanced "smart" meters, communication infrastructure, and data management systems. The smart meters can collect granular, near real-time data that enables new customer programs and features. One illustration of how Customer Experience uses this technology is the Interactive Bill, which features a daily and monthly usage graph and information regarding how weather affected the customer's bill.

The DAP software operating system allows Tampa Electric to collect and analyze data including transformer loading, events, and alarms and identifies proactive substation transformer maintenance and replacements. The company uses this data to proactively reduce customer outages. The DAP also provides real-time, granular customer data to the call center to help Customer Service Professionals respond to customer questions and enable first call resolution.

DI consists of applications that reside on the company's meters and enable the company to analyze data at the grid edge. DI uses the following applications: (1) high impedance, which detects faulty equipment on customer and utility assets; (2) high temperature, which identifies faulty customer equipment; (3) location awareness, which improves system accuracy and allows quicker response to customer outages; and (4) active transformer loading and monitoring, which helps the company better understand customer-owned equipment and the impact it has on our system.

The AIML applications consist of various programs and tools, including natural language models such as ChatGPT, that enable the company to process data quickly and effectively. With AIML, Tampa Electric can automate processes that directly improve customer experience and reliability. The company first used these applications as a limited scope pilot project within Human Resources as an expert advisor for our 2024 Benefits Open Enrollment.

Q. What major OT applications support Electric Delivery activities?

A. The following OT applications support the Electric Delivery department: (1) the Energy Management System ("EMS"); (2) the Advanced Distribution Management System ("ADMS"); (3)

AMI; (4) the Work Management System ("WMS"); (5) the Geographic Information System ("GIS"); (6) SLV; (7) the Grid Communication Network project; (8) and the ARCOS Resource Management Platform.

Q. Please describe the EMS, ADMS, and SCADA applications and how they support the Electric Delivery department.

A. EMS is the core application suite for electric grid operations and interfaces with the ADMS system. EMS enables the grid operators within Electric Delivery to better control, optimize, and analyze the transmission and distribution electric grid in real time.

The SCADA system is used by the Electric Delivery department to retrieve data and alarms across the system and control devices or machines at remote sites. EMS uses SCADA to centrally monitor and control the grid to minimize risk and increase flexibility.

ADMS is a software platform that enables the company's distribution system operators to control and optimize the distribution network. ADMS works in conjunction with SCADA. ADMS also coordinates and operates smart grid operating technology, including Distributed Energy

Resources ("DER") and intelligent distribution controls (*e.g.*, smart switches).

Together, these systems allow central monitoring and control of the distribution grid and, in conjunction with AMI, CRB, and the Outage Map, provide outage management and outage restoration capabilities. Each of these systems contributes to customer reliability.

Q. Please describe the AMI system and how it supports the Electric Delivery department.

A. AMI supports Electric Delivery by offering the ability for team members to read, disconnect, and reconnect meters remotely, reducing the need to dispatch field workers. This system also enables the company to monitor data in real time and detect outages.

Q. Please describe the WMS and GIS systems and how they support the Electric Delivery department.

A. The company's Electric Delivery department uses the WMS application suite (Workpro) to plan, track, organize, and dispatch field crews to construct, maintain, operate, and repair our transmission and distribution assets. The GIS is a mapping system that stores and manages the geographic coordinates of distribution, transmission, and telecom equipment. The GIS, along with WMS, creates a starting point for designers to plan and engineer work. Together, the WMS and GIS application suites enable Electric Delivery to efficiently plan projects and schedule team members and contractors in the field.

Q. Please describe the SLV application and how it supports the Electric Delivery department.

A. The SLV application allows team members to remotely control and monitor outdoor lighting equipment and supports the company's asset management program, which is described in the direct testimony of Tampa Electric witness Chip Whitworth. The SLV application also provides data analytics that can be used to improve energy efficiency. The SLV technology can also enable advanced "smart city" functionalities such as traffic management, smart parking, and transportation optimization. The Electric Delivery department also uses SLV to support the company's growing smart light-emitting diode ("LED") streetlight operations and to automate and simplify the management of the lighting infrastructure. Finally, SLV's maintenance prediction capabilities allow the company to detect issues early, preventing major outages and reducing downtime.

Q. Please describe the ARCOS Resource Management Platform ("ARCOS") and how it supports the Electric Delivery department.

A. ARCOS is a field scheduling tool used by the Electric Delivery department that allows the company to track crews in the field in both "blue sky" and "gray sky" weather conditions. ARCOS automates and optimizes resource management and emergency response processes. The benefits of ARCOS include efficient resource management, automated callout and scheduling, increased visibility of field crews, and optimized workforce utilization.

Q. What major OT applications support Energy Supply activities?

A. The Energy Supply department uses (1) WORKman; (2) the Lock Out Tag Out ("LOTO") application NiSoft; (3) Data Historian; (4) Power Plant Controllers ("PPC"); and (5) SCADA.

Q. Please describe these five applications and how they support the Energy Supply department.

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A. WORKman helps Energy Supply organize asset information, optimize asset maintenance, efficiently schedule work, and manage materials used at the various Energy Supply work sites.

Energy Supply uses the LOTO application NiSoft to facilitate the high-energy control procedure of isolating equipment prior to any maintenance or emergency work. The LOTO system supports the company’s safety goals by standardizing safety practices, enhancing communication, and reducing equipment damage.

Energy Supply relies on the Data Historian application to archive operational telemetry for analysis. The operational data is used to analyze and optimize generation system performance.

The PPC application integrates, monitors, and autonomously controls the operation of the company’s solar generation assets.

Lastly, similar to Electric Delivery, the Energy Supply department uses SCADA to acquire data from the PPC, equipment, and sensors throughout generating units (both combustion turbines and renewables). Team members use SCADA

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to monitor operations and control the generation units.

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

A. All the applications discussed above help the company comply with legal and regulatory requirements. For example, AMI provides bill ready data that is validated and vetted through the Meter Data Management System to ensure customers receive timely, accurate bills. SLV quickly detects and reports streetlight outages, and contributes to increased public safety because restoration occurs more quickly. ADMS notifies the company's systems and customers of outages and outage restorations, resulting in quicker restorations. GIS is the core connectivity and field asset model that feeds data to multiple other applications, including ADMS.

SUCCESSES SINCE TAMPA ELECTRIC'S LAST BASE RATE PROCEEDING

Q. You previously described several applications and technologies that the OT&S department uses to support Customer Experience, Electric Delivery, and Energy Supply. Which of these technologies went into service after the company's last base rate case in 2021?

A. The following applications were placed into service since 2021: AMI, DAP, DI, AIML, SLV, ARCOS, and the 3.21 version update to ADMS.

Q. How did these projects benefit the company and its customers?

A. The benefits of each project are explained below.

AMI

Tampa Electric's use of AMI technology reduced bill estimations and allows quicker restoration of disconnected customers. The company's bill estimation rate for AMI meters is 0.1 percent and over 98 percent of AMI meters are reconnected remotely, which avoids the expense of dispatching technicians ("truck rolls") to the premise.

DAP

Tampa Electric uses DAP to provide customer usage data through a web portal. As I previously explained, the DAP application also allows the company to monitor usage metrics, meter events, and alarms. The use of this technology results in fewer outages and reduces the need for truck rolls.

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DI

DI improves the safety of customers by providing the company with awareness of high meter temperature and high impedance, which may indicate a dangerous situation such as a failing connector or a bad connection on customer equipment in the early stage of failure. These items are not normally identified until after failure, and failures can cause unplanned outages, potential energized wire down situations, prolonged unplanned customer outages, or poor power quality. DI also improves reliability for customers by alerting the company to situations that may cause unplanned outages. Finally, DI gives the company more accurate mapping of our physical network, which helps reduce outage restoration times.

AIML

As discussed above, the AIML applications were implemented as a limited scope pilot project for the company's most recent benefits Open Enrollment process. The application absorbed all the open enrollment 2024 health insurance plans to train the system to automatically answer employee questions instead of an HR representative. This was done to improve efficiency. This project created a platform that will allow us to automate and enhance business processes, which will result in more consistent, quicker responses, enhanced service to customers, and potentially savings in O&M expense.

SLV

This application provided the company with automation and increased visibility into the lighting network, which resulted in a 75 percent reduction in truck rolls for move-in and move-out tickets. SLV also provided a 38 percent reduction in truck rolls during Hurricane Idalia by giving us better visibility into the operation and condition of the lighting system.

ADMS

The ADMS Upgrade project provides additional functionality to improve customer outage estimated time to restore ("ETR") calculations and reporting.

ARCOS

The ARCOS upgrade provided the company with gains in service, economics, and reliability. The direct benefits included improved accuracy in crew callouts, real time personnel and crew updates, and increased visibility of circuit information and status.

PREPARING FOR THE FUTURE

Q. How is the OT&S department planning for the future?

A. The company is planning a group of projects, known as the "Grid Reliability and Resilience Projects." These projects will build on Tampa Electric's existing grid modernization strategy and will provide new and enhanced functionality. Additionally, they will help the company adapt to changes in how our customers use and, in some cases, produce electricity. One of these projects is a Grid Communication Network Project, which is a high bandwidth, low latency network. The Grid Communication Network project will handle the surge of data from the many devices, such as smart switches, which enable remote monitoring, control, and automation of power distribution and capacitor banks. These devices play a crucial role in optimizing the performance and efficiency of the distribution system.

OT&S CAPITAL INVESTMENTS AND BUDGET

Q. The company's last rate case was resolved via the 2021 Stipulation and Settlement Agreement ("2021 Agreement") approved by the Commission in Order No. PSC-2021-0423-S-EI, dated November 10, 2021. How much capital did the company invest in the OT&S area during the three-year term of the 2021 Agreement from 2022 through 2024?

A. For the period 2022 through 2024, the company invested approximately $257.6 million, of which $228.9 million will be recovered through base rates. Document No. 2 of my Exhibit summarizes the company's OT&S capital investments over this period.

Q. What capital projects are included in the company's OT&S capital spending during the period 2022 through 2024 and what was the capital investment for each project?

A. The OT&S capital investment in 2022 through 2024 is shown in the following table.

2022-2024 Major Capital Projects

	Total
Other	60,153,819
Blanket - Lighting	48,623,384
DAP	27,370,247
OT Application	22,192,038
Lighting - Growth	15,581,296
Grid Reliability and Resilience Projects	21,246,304
Blanket - Meter	13,695,381
AMI	11,704,918
ADMS	5,275,120
ES Capital Maintenance/Improvement Project/Program	1,288,501
Meter Operations	765,696
Lighting - Operations	608,823
ED Capital Maintenance/Improvement Project/Program	200,000
BLSN	158,172
Total	**228,863,698**

Q. How much did the company invest for the AMI project during the period 2022 through 2024?

A. Tampa Electric incurred $11.7 million in costs associated with AMI during the period 2022 through 2024. Tampa Electric's conversion to AMI meters from Advanced Meter Reading ("AMR") meters was approved by the Commission as part of the 2021 Agreement. The company completed the conversion in 2021 and has continued to enhance the AMI system since that time. AMI benefits customers because it makes meter data available in close to real time and allows Tampa Electric to analyze system capacity, loading of assets, and other operating conditions more quickly. AMI also makes it possible to create new rate programs for customers or provide them with their data to help explain usage patterns or billing.

BLANKET LIGHTING PROJECTS

Q. Please describe the Blanket - Lighting projects and why they are needed.

A. These projects include the purchase and replacement of streetlights across the service territory. The purchases are needed to accommodate growth, respond to customer requests, and ensure continued support of the lighting network.

Q. What steps will the company take to ensure these projects

are completed at the lowest reasonable cost?

A. Tampa Electric selects a vendor from a group of qualified contractors for each project. The contracting pool was selected though a bidding process. This selection is based on both cost and the quality of work offered by each vendor. The company also negotiates pricing to ensure the purchases are in line with the industry.

Q. What benefits will the Blanket – Lighting projects provide to customers?

A. The benefits include meeting customer demand, public safety, reliability, and integration with smart city technology as I described previously in my direct testimony.

Q. Will these projects require new employees?

A. No.

<u>OTHER PROJECTS</u>

Q. Please describe the projects in the "Other" category and why they are needed.

A. Projects in the "Other" category include various telecom and analytics projects. These projects are needed to support routine customer growth and operations.

Q. What steps will the company take to ensure these projects are completed at the lowest reasonable cost?

A. These projects were competitively bid with standard project practices.

Q. What benefits will the Other projects provide to customers?

A. The benefits include the ability to support continued reliability and standard field operations.

Q. Will these projects require new employees?

A. No.

GRID RELIABILITY AND RESILIENCE PROJECTS

Q. What are the Grid Reliability and Resilience Projects?

A. The Grid Reliability and Resilience Projects are comprised of six interrelated components including: (1) Control Systems OT; (2) Back Office IT; (3) Field Devices;

(4) Substation; (5) DER Infrastructure; and (6) the Grid Communication Network Project. My testimony addresses the first five components of the Grid Reliabilty and Resilience Projects first, and then I will provide additional detail about the Grid Communication Network component separately.

Q. Why are these five components needed?

A. These five components are designed to address changes to the grid, including increased digitalization, decentralization, and decarbonization, an increase in distributed generation (e.g., roof top solar), increasing use of electric vehicles by residential customers and commercial fleets, and growth in other distributed technologies such as battery storage. Through the adoption of intelligent field devices, identification of electric vehicles ("EV"), and management of distributed energy resources ("DER"), these projects enable the company to meet rising customer demand and enhance reliability by reducing the frequency, duration, and impact of outages, both sustained and momentary. Overall, these efforts are crucial for meeting customer demand, building a resilient grid and adapting to changes in how our customers use, and sometimes produce, energy.

Q. What is the Control Systems OT component?

A. The Control Systems OT component monitors and controls assets in the field. In an increasingly decentralized grid, the number of controllable grid devices is growing exponentially, and the importance of the company’s monitoring and control capabilities is also growing. The company can use these devices to diagnose system conditions and respond through automation and remote action. The Control Systems OT work will support the company's objectives to build an adaptable grid, improve operational performance, and reduce the frequency and duration of customer outages. The Control Systems OT component will work in concert with controllable field assets and our high-speed telecommunications network to achieve reliability improvements.

Q. What is the Back Office IT component?

A. The Back-Office IT component includes system implementation, software licensing, interfaces, data migration, and new configurations for back-office systems such as GIS and WMS. These enhancements will have several benefits. First, they will revolutionize Tampa Electric’s planning, building, and grid management while enhancing customer programs and billing. Second, these consolidated systems will replace obsolete and end-of-life systems, streamline core processes, facilitate data exchange, and support field installation of other program components. Finally, these upgrades will boost work efficiency, throughput, and adaptability to the evolving grid.

Q. What is the Field Devices component?

A. The Field Devices component involves deploying a variety of detection and operational devices along the company's circuits to provide the company with greater monitoring and control over the system. These Field Devices will improve reliability by taking automatic action to mitigate adverse grid events or by providing operators with greater control for fault location and isolation, switching, and voltage management. More granular control of distribution circuits is a necessary capability as distributed generation, storage, and electric vehicles with bi-directional charging capabilities (known as "vehicle to grid") inject power and create bi-directional power flows or voltage fluctuations. These Field Devices will mitigate the outage impacts of faults, minimize the duration of outages through fault location and isolation, and provide data back to operators for improved system diagnostics.

Some examples of Field Devices are equipment such as reclosers, regulators, line sensors, and automatic lateral switches.

Q. What is the Substation component?

A. The Substation component modernizes and replaces obsolete and end-of-life equipment to prepare for bi-directional power flows, including system protection and optimization of circuit level actions. Replacing electro-mechanical or other end-of-life equipment at our substations with SCADA-enabled gear increases the company’s ability to remotely monitor assets and operate fault detection, service restoration, and voltage optimization control protocols. These Substation activities will improve the reliability, system control, power flow efficiency, and operational efficiency of substation operations.

Q. What is the DER Infrastructure component?

A. The DER Infrastructure component implements monitoring and controls that will coordinate DER and EV on our system. These controls improve the efficiency of the bulk power generation and transmission system by upgrading existing infrastructure like wires and transformers that are

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overloaded from DER, developing standards for smart inverters that will connect the grid with customer devices, and developing interconnections to integrate DER information into the Distributed Energy Resources Management System ("DERMS"). This component will establish interconnection standards, improve customer awareness, and develop smart technologies to collectively strengthen the grid's capacity to seamlessly integrate DER and EV.

Q. What steps will the company take to ensure these five components of the Grid Reliabilty and Resilience Projects are completed at the lowest reasonable cost?

A. As explained in the direct testimony of Mr. Whitworth, Tampa Electric plans to aggregate the Grid Reliability and Resilience Projects so that the company can optimize capital spending, maximize functionality, and achieve greater efficiency in resource deployment. This coordinated approach enables centralized project management, reduces redundancy, and enhances resource efficiency.

Q. What benefits will these five components of the Grid Reliability and Resilience Projects provide to customers?

A. The Grid Reliability and Resilience Projects not only promise tangible benefits such as enhanced reliability and reduced O&M expense, but also facilitate customer-focused programs to improve fault detection, minimize downtime, and expedite restoration. The Grid Reliability and Resilience Projects will also facilitate the integration of DER and enhance grid management, leading to reduced energy losses and increased efficiency, especially during peak load conditions. These benefits are also described in greater detail in the direct testimony of Mr. Whitworth.

Q. Will these five components of the Grid Reliability and Resilience Projects require new employees?

A. Yes, the company expects that new employees will be necessary to support these projects. The company does not expect, however, that these positions will be necessary in the 2025 test year.

GRID COMMUNICATION NETWORK PROJECT

Q. What is the Grid Communication Network Project and why is it needed?

A. Tampa Electric currently operates numerous field devices on its distribution system including AMI meters, Fault

Location Isolation System Restoration ("FLISR") systems, and other similar devices. The company also plans to install additional devices through the Grid Reliability and Resilience Projects over the next several years. The existing radio-based SCADA system used to communicate with the company's existing field devices, however, lacks any additional bandwidth to support these future projects. The Grid Communication Network Project addresses this need for data transmission and communication through construction of a PLTE, or a private cellular network, which includes radios, antennae, and server core systems. This project is necessary to provide communications to existing devices and to the new Grid Reliability and Resilience Project devices using 4G and 5G frequency bands.

The Grid Communication Network Project supports the company's grid modernization strategy and Grid Reliability and Resilience Projects in two primary ways.

First, the Grid Communication Network is the most cost-effective means to seamlessly and quickly gather the data generated by the company's existing and future field devices, to make full use of those devices, and to improve the customer experience.

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Second, the Grid Communication Network provides the most efficient pathway to manage the proliferation of EV charging equipment and customer-owned renewable generation on the company's system.

In short, the Grid Communication Network Project provides the communication backbone for future grid reliability and resilience initiatives and will help ensure overall grid stability.

Q. What alternatives to this project did you consider?

A. The company considered several alternatives to the Grid Communication Network Project.

First, the company considered expanding its existing fiber network. This option is not as cost-effective as building out a PLTE cellular network due to the significant costs necessary to expand the existing fiber optic network to connect to the growing fleet of smart devices and because it would be very costly to maintain.

The company also considered using a public LTE network. The company decided against this option because reliance on an unsecured, public LTE network may expose the company to security risks and limit the potential for migration of Tampa Electric services to a near-future 5G platform.

Finally, the company determined that it could not move forward with the existing radio-based SCADA system because all channels are already at capacity. In fact, the existing communications volume on the system is already resulting in communication delays. Due to these constraints, remaining with the existing system would also mean that the company could not move forward with the Grid Reliability and Resilience Projects at a pace and cost that would bring the best value to our customers.

Q. What steps will the company take to ensure the Grid Communication Network Project is completed at the lowest reasonable cost?

A. In 2022, Tampa Electric engaged an expert, third-party consultant, Burns & McDonnell ("BMD"), to conduct a detailed analysis of existing and future field network options to complete buildout of a PLTE network. The scope of services for this analysis included the development of a comprehensive list of use cases, business requirements, Total Cost of Ownership ("TCO") estimates, and technical requirements for the cellular communications infrastructure for this network. These specifications were then incorporated into a request for proposals for the provision of the required equipment and services.

The BMD analysis:

- Identified the existing technology platforms currently in service on Tampa Electric's system that would benefit from a PLTE network, as well as potential future technologies that would benefit from the network.
- Identified the potential benefits of a PLTE network and the projects it would enable, which allows Tampa Electric to prioritize the deployment of these future projects.
- Provided a TCO based on a 3-year deployment of the PLTE network, and a 20-year deployment of technologies enabled by the network.
- Provided a cost-benefit analysis showing a four-to-five year payback for Tampa Electric's initial investment.

Q. What benefits will this project provide to customers?

A. The Grid Communication Network Project will benefit customers in three major ways.

First, this project enables communication with current and future smart distribution equipment and allows the company to automate devices, both of which will improve reliability and reduce long-term O&M costs.

Second, the Grid Communication Network enables the company's access to new data streams that are required to operate the grid safely and reliably in a decentralized world where EV and DER are installed at customer locations across the system.

Third, the Grid Communication Network is scalable and will help the company identify bi-directional flows, EV penetration, and DER penetration to determine where needed capital improvements will be most effective.

DAP PROJECT

Q. What is the DAP Project?

A. As I previously explained, DAP enables long term data storage of AMI meter data and facilitates analysis of that data for business insights and intelligence.

Q. What alternatives to this project did you consider?

A. Tampa Electric considered foregoing this project, but that would leave the company without the data analytics capabilities DAP offers and would not allow the company to fully use the existing AMI meters.

Q. What steps did the company take to ensure the project was completed at the lowest reasonable cost?

A. Tampa Electric used a competitive bid process to complete this project, as well as strong project management and cost control.

Q. What benefits will this project provide to customers?

A. The DAP system provides several benefits to customers. First, DAP gives Tampa Electric’s customers greater control over their energy bills by providing them with information regarding their daily energy usage and average daily temperature through the company’s new Interactive Bill. Second, the DAP system provides the company’s customer service professionals with additional data that can help them resolve customer calls regarding high bills. Third, DAP improves the company’s home energy audit program by providing the home energy auditors with additional data they can use to assess home energy consumption. Fourth, DAP improves billing accuracy. Finally, the project will potentially lead to cost savings by helping the company optimize capital investments and identify operational efficiencies.

Q. Will the DAP Project require new employees?

A. Yes. This project will require a Data Analyst and a Data Director to support this project. We expect to fill these positions in the next year.

OT APPLICATION PROJECTS

Q. Please describe the OT Application projects and why they are needed.

A. OT applications enable the operational control of our power plants and grid systems; network communication and management of operational data; and collection and analysis of sensor data, which helps the company understand the condition and performance of our grid. OT applications also facilitate the maintenance and operation of the grid assets. These systems are required to operate our grid safely, reliably, cost-effectively and in compliance with all legal obligations.

Q. What steps will the company take to ensure the projects

are completed at the lowest reasonable cost?

A. Tampa Electric evaluates alternatives and best practices in the industry to select a cost-effective solution.

Q. What benefits will the OT Application projects provide to customers?

A. Each OT application serves a specific function in the electric grid and provides benefits to our customers related to that OT application's function. I previously described the functions and benefits of our OT applications such as the Work and Asset Management System, ADMS, and EMS in my direct testimony.

<u>BLANKET METER PROJECTS</u>

Q. Please describe the Blanket - Meter projects and why they are needed.

A. These projects include the purchase and replacement of failed electric meters across the company's service territory. The purchases are needed to accommodate growth and provide continued support for the communication network.

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Q. What steps will the company take to ensure these projects are completed at the lowest reasonable cost?

A. Tampa Electric selected a vendor through an RFP process that involved multiple meter vendors. The company negotiated a multi-year agreement with the selected vendor that includes negotiated pricing and pricing discounts.

Q. What benefits will the Blanket - Meter projects provide to customers?

A. As I previously explained, AMI meters have improved networking capabilities to provide faster and more reliable responses to customers for switching and data analysis.

Q. Will the project require new employees?

A. No.

<u>LIGHTING GROWTH PROJECTS</u>

Q. Please describe the Lighting Growth projects and why they are needed.

A. Tampa Electric's LS-2 customized lighting tariff allows customers to request custom lighting installations like solar powered or decorative lighting. The projects in the Lighting Growth category are necessary to satisfy customer lighting service requests.

Q. What steps will the company take to ensure these projects are completed at the lowest reasonable cost?

A. These projects use fixed pricing established through competitive bids.

Q. What benefits will the Lighting Growth projects provide to customers?

A. These projects allow customers to satisfy their lighting needs in a cost-effective, hassle-free manner by using Tampa Electric's expertise.

Q. Will the project require new employees?

A. No.

<u>THE ADMS 3.12 UPGRADE PROJECT</u>

Q. What is the ADMS 3.12 upgrade project?

A. As I mentioned earlier, ADMS includes functions that integrate SCADA, advanced network applications, and outage management to enhance the outage restoration process and optimize the performance of the distribution grid. The ADMS functions implemented through this upgrade include real time distribution power flow; fault location, isolation, and service restoration ("FLISR"); Volt/Volt-ampere Reactive ("VAR") optimization; and the ability to support, monitor, and control DER such as customer-owned solar and batteries. The ADMS solution will put Tampa Electric in a position to provide power that's safer, more reliable, and more efficient.

Q. Why was the ADMS 3.12 upgrade project needed?

A. As I previously explained, this ADMS upgrade will provide several new features that will improve grid operations and provide benefits for our customers.

Q. What alternatives to this project did you consider?

A. Tampa Electric also considered upgrading distinct components of ADMS over a longer time horizon. This option would have introduced integration risks and increased the long-term cost of completing the work.

Q. What steps did the company take to ensure the project was completed at the lowest reasonable cost?

A. In April 2017, Tampa Electric engaged in a Request for Information ("RFI") process with five vendors to solicit information regarding ADMS solutions available in the marketplace. Tampa Electric also engaged an external utility expert to ensure that the RFI process was comprehensive and would result in a structured and fair result for both Tampa Electric and the bidding vendors. The final RFI consisted of 880 requirements that were sent to six vendors. Tampa Electric evaluated the bids, selected the top two vendors, and asked those vendors to visit Tampa Electric and provide a more detailed demonstration of their proposed solutions. In addition to the demonstration, Tampa Electric sent functional experts to Alabama Power and Arizona Power to evaluate the vendors' products in a real-world use situation. Based on the combined scoring of the initial RFI and the on-site demonstrations, Tampa Electric selected General Electric ("GE") Alstom as the preferred provider.

Q. What benefits will this project provide to customers?

A. The ADMS 3.12 upgrade project provides additional functionality to improve customer outage estimated time to restore ("ETR") calculations and reporting. The integration of ADMS with AMI data allows the company to identify customer outages and achieve faster restoration. It also improves the company's ability to adjust and coordinate field devices that improve reliability and power quality. Finally, implementation of the ADMS 3.12 upgrade allows the company to develop DER management capabilities.

Q. Will the project require new employees?

A. Yes. During 2021 and 2022, the OT&S department added two modeling technicians team members, two ADMS Engineers, and two IT support employees. The company expects to add one employee working with DERMS to support ADMS in 2027.

<u>METER OPERATIONS PROJECT</u>

Q. Please describe the Meter Operations Project, why it is needed, and how it will benefit customers.

A. The Meter Operations Project is a meter firmware upgrade. Firmware is a set of embedded software instructions that govern the operation of a metering device, including managing the collection, processing, and transmission of data such as electricity consumption. The meter firmware includes algorithms for accurate data acquisition, real-time processing, and communication with external systems. This meter firmware upgrade significantly benefits customers through various enhancements, including remote monitoring and management, and will allow the company to swiftly address issues and minimize downtime without physically accessing the meters. Regular updates also ensure compatibility with new technologies. This upgrade also included bug fixes and stability improvements which contribute to more reliable service, fewer disruptions, and an enhanced customer experience. We expect to complete the project in 2025.

Q. What steps will the company take to ensure the project is completed at the lowest reasonable cost?

A. Tampa Electric used existing employees to complete this project and distributed the firmware "over the air" using the existing AMI network. This avoids the expense of sending employees out into the field.

Q. Will the project require new employees?

A. No.

ELECTRIC DELIVERY CAPITAL MAINTENANCE IMPROVEMENT PROJECTS

Q. Please describe the Electric Delivery Capital Maintenance Improvement Projects ("ED Capital Maintenance Improvement Projects") and why they are needed.

A. Tampa Electric monitors the condition and performance of grid assets to evaluate risks to reliable performance. When the company identifies a common risk of failure in many similar or identical assets, such as 69 kV relays or transmission insulators, Tampa Electric develops an asset class mitigation plan to proactively address the identified risk across the entire group of assets.

Q. What steps will the company take to ensure the ED Capital Maintenance Improvement Projects are completed at the lowest reasonable cost?

A. Proactive work is safer and lower cost than reactive maintenance. Performing work systematically for a group of assets allows the company to achieve larger economies of scale through bundling and bidding of work, which ensures that we obtain the lowest reasonable cost.

Q. What benefits will the ED Capital Maintenance Improvement Projects provide to customers?

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A. Tampa Electric's ED Capital Maintenance Improvement Projects improve reliability for our customers by mitigatining failures. These projects also benefit customers by providing reduced costs associated with equipment replacement. Specifically, these projects enable them to plan the procurement and installation of equipment, which reduces cost compared to reactive repair or replacement.

Q. Will these projects require new employees?

A. No.

ENERGY SUPPLY CAPITAL MAINTENANCE IMPROVEMENT PROJECTS

Q. Please describe the Energy Supply Capital Maintenance Improvement Projects ("ES Capital Maintenance Improvement Projects") and why they are needed.

A. Just as with our transmission and distribution grid, Tampa Electric also monitors the condition and performance of our generation assets, including motors, pumps, pipes, etc. These projects facilitate this monitoring and allow the company to proactively replace components before they fail, to identify opportunities to improve unit efficiency and performance, and to improve safety.

Q. What steps will the company take to ensure the ES Capital Maintenance Improvement Projects are completed at the lowest reasonable cost?

A. Proactive work is safer and lower cost than reactive maintenance. Performing work systematically for a group of assets allows Tampa Electric to achieve larger economies of scale through bundling and bidding work, which ensures that we obtain the lowest reasonable cost.

Q. What benefits will the ES Capital Maintenance Improvement Projects provide to customers?

A. Tampa Electric's ES Capital Maintenance Improvement Projects ensure proactive mitigation of failures, which improves reliability, and proactive procurement and planning of the capital work which reduces cost. Where applicable, the team ensures we comply with all regulatory requirements as well.

Q. Will these projects require new employees?

A. No.

C7-458

LIGHTING OPERATIONS PROJECTS

Q. Please describe the Lighting Operations (Smart Street Light) projects and why they are needed.

A. These projects are installations of intelligent lighting systems to fulfill customer requests. These smart lighting fixtures enhance safety and security, provide data insights and analytics, and offer customization and flexibility to meet specific community needs.

Q. What steps will the company take to ensure these projects are completed at the lowest reasonable cost?

A. For each project, Tampa Electric completes a cost analysis to determine the budget and allocate sufficient resources. The company then completes a vendor selection and negotiation process to secure favorable terms and pricing.

Q. What benefits will the Lighting Operations projects provide to customers?

A. The benefits of these projects include enhanced safety, reliability, and integration with smart technology.

Q. Will the Lighting Operations (Smart Street Light) projects require new employees?

A. No.

BRIGHT LIGHTS, SAFE NIGHTS ("BLSN")

Q. What is the BLSN Project?

A. The BLSN project supports the local community's safety. The City of Tampa partnered with Tampa Electric to provide leased lighting services within high crime areas and on roadways or intersections with more vehicle incidents to enhance safety.

Q. What steps did the company take to ensure the BLSN Project was completed at the lowest reasonable cost?

A. Tampa Electric negotiated labor rates for cost control and did not begin work until after the design was approved by the customer. Designs were developed to an IES standard to assure the right light levels were provided at each location, which minimizes potential for rework by ensuring that safety and compliance requirements are met prior to installation.

Q. What benefits will the BLSN Project provide to customers?

A. City of Tampa reported that the project resulted in a reduction of crime or vehicular incidents and reduced officer overtime as there were fewer incidents to respond to.

Q. Will the project require new employees?

A. No.

Q. What major capital projects are planned in the OT area for 2025?

A. The major capital projects planned for 2025 are included in the following table. Additional detail is included in Document No. 2 of my exhibit.

2025 Major Capital Projects

	2025
Grid Reliability and Resilience Projects	65,871,743
DAP	18,075,079
Blanket - Lighting	16,069,585
OT Application	11,312,970
Other	4,188,739
Blanket - Meter	3,867,678
ED Capital Maintenance/Improvement Project/Program	2,900,685
Meter Operations	2,815,381
AMI	2,038,651
ES Capital Maintenance/Improvement Project/Program	665,000
Lighting - Growth	550,000
Lighting - Operations	500,000
Grand Total	**128,855,509**

Q. Are any of the projects, or groups of projects, planned for 2025 continuations of projects the OT&S department undertook in 2022 through 2024?

A. Yes. The following is a list of projects or groups of projects that are continuations of the work the the OT&S department undertook during 2022 through 2024.

- Blanket – Lighting
- OT Application
- Grid Reliability and Resilience Projects (including Grid Communication Network Project)
- Other
- Blanket - Meter
- ED Capital Maintenance/Improvement
- Meter Operations
- AMI
- ES Capital Maintenance/Improvement
- Lighting – Growth
- Lighting – Operations

I previously described the need for these projects, how they benefit customers, and the steps the company takes to complete these projects at a reasonable cost in my discussion of our capital investments in the years 2022 through 2024. Our planned investments in these areas in

2025 are necessary and prudent for the reasons I previously described.

DAP PROJECTS

Q. Please describe the DAP projects and why they are needed.

A. The DAP projects planned for 2025 will build on the existing DAP system and provide new capabilities, including the ability to receive and process near-real time data. This will support customer programs, such as the Interactive bill, and safety programs, such as the detection of downed energized conductors. It will support more efficient dispatching due to access to current state demand and generation data. Tampa Electric will be able to receive and analyze DI data to support advanced analytics such as detection of EV charging activities and location of "ghost meters," or meters without a known installation location. Finally, these projects provide the company the ability to monitor new characteristics of the distribution system, including transformer phase imbalances and actual transformer and circuit loading characteristics. This will allow the company to identify and resolve abnormal conditions.

Q. What steps will the company take to ensure these projects

are completed at the lowest reasonable cost?

A. The company will use existing AMI technology to save costs. The company will also use its procurement process along with competitive bids to ensure projects are completed at a reasonable cost.

Q. What benefits will the DAP projects provide to customers?

A. The DAP projects will allow the company to improve its unit dispatching and generation decisions, which will lead to more efficient operations and the potential for reduced fuel costs. These projects will improve employee and customer safety by enabling the detection of serious issues that could cause injury or death, such as back-feeding onto the distribution system or downed energized conductors. These projects also will enable and support customer programs such as improvements to the Interactive Bill and new time-of-use programs.

Q. When will these projects be placed into service?

A. Tampa Electric expects to complete some DAP projects in 2024 and others in 2025.

<u>AMI PROJECTS</u>

Q. Please describe the AMI Projects and why they are needed.

A. The AMI project builds on our existing AMI infrastructure by transitioning our AMI and lighting networks to a common platform. This will allow the same team members to manage both AMI meters and lighting. This project also will examine potential future use cases for automation, AI, and ML for AMI and lighting.

Q. What steps will the company take to ensure these projects are completed at the lowest reasonable cost?

A. The company will use the existing streetlight network to save costs, and the company will select vendors and contractors through our competitive procurement processes.

Q. What benefits will the AMI projects provide to customers?

A. Using the same platform for the AMI and lighting networks improves speed and efficiency in serving customer disconnection, reconnection, and billing needs.

Q. When will these projects be placed into service?

C7-465

A. Tampa Electric expects to complete the AMI projects in 2025.

Q. What is the total capital investment in OT for the above-described projects between 2022 and 2025?

A. The total capital investment for the above-described projects is $478.6 million, of which $357.7 million is in rate base expenditures, from 2022 to 2025.

SUBSEQUENT YEAR ADJUSTMENT

Q. Please list the SYA project for which you are responsible in this proceeding.

A. I am responsible for explaining the Grid Reliability and Resilience Projects that are included in the company's proposed 2026 SYA and 2027 SYA. I will describe the three components which go into service during 2025 and 2026. In August 2025, the Grid Communication Network component goes into service. In September 2026, the Customer Information Device Expansion components go into service, and in December 2026, the Grid Communication Network Hardware, Work Management, and Control Systems components go into service.

C7-466

GRID COMMUNICATION NETWORK – 2026 SYA

Q. Please describe the Grid Communication Network investment in the SYA and why it is necessary.

A. The Grid Communication Network investment in the 2026 SYA consists of acquiring the license for a 3x3 MHz band in the 900 MHz spectrum to provide private and secure 4G and 5G communications to field devices. It is expected to cost $27.6 million and to be in service in August 2025.

This component is a standards-based technology that provides a communications network to connect devices on the grid. The networks have been designed for cybersecurity, resiliency, reliability, and performance and control. This component also reduces the reliance on public carriers, reducing operating expenses and creating a private, converged network where we can prioritize and manage our own network traffic ensuring efficient and reliable communication within the grid system.

Q. How will this component benefit customers?

A. I previously described the benefits of the Grid Communication Network Project in my discussion of the company’s capital investments in the years 2022-2024. In short, the Grid Communication Network Project will provide high-speed communication between the Control Systems and Field Device components to improve power quality and reliability performance.

CUSTOMER INFORMATION DEVICE EXPANSION – 2026 AND 2027 SYA

Q. Please describe the Customer Information Device Expansion and why it is necessary.

A. The Customer Information Device Expansion work falls into the Back Office IT component of the Grid Reliability and Resilience Projects. This consists of reconstructed data models for lighting and non-meter devices, integrations with existing systems, and revamped business processes for device billing to better facilitate billing, unlock growth opportunities in customer programs, and improve operational efficiencies across utility services. They are expected to cost $24.3 million and to be in service in September 2026. As a result, this component is contained in both the 2026 SYA amount and the 2027 SYA amount.

This component changes the billing approach for non-meter devices, eliminating reliance on workarounds, and prepares the utility for growth in decentralized energy resources and customer engagement.

C7-468

Q. How will these components benefit customers?

A. The Customer Information Device Expansion component enhances billing transparency, enables the ability to set up an online marketplace for devices (lights, surge protection, etc.) and helps to streamline business processes such as reconnects and disconnects. This leads to greater efficiency in the handling of devices on the system, creating an optimal customer experience.

GRID COMMUNICATION NETWORK HARDWARE, BACK OFFICE IT SYSTEMS, AND CONTROL SYSTEMS - 2026 AND 2027 SYA

Q. Please describe the Grid Communication Network Hardware, Back Office IT Systems and Control Systems components and why they are necessary.

A. The Grid Communication Network Hardware, Back Office IT Systems, and Control Systems components that the company plans to place in service in 2026 consist of line sensor software, Private LTE implementation, a Work Management System (WMS), and Distribution Planning Software Upgrades. These components are expected to cost $120.6 million and to be in service in December 2026. As a result, these components are contained in both the 2026 SYA amount and the 2027 SYA amount.

C7-469

This work will better facilitate advanced grid monitoring, enhance operational efficiency, and improve the accuracy of distribution planning and design. It will also improve grid management and maintenance workflows, provide a robust communication network for real-time data transmission, and leverage real-time data for more precise planning and operational decisions, significantly enhancing the utility’s operational capabilities and service reliability.

Q. How will these components benefit customers?

A. As previously mentioned, the Grid Communication Network Hardware, Back Office IT Systems, and Control Systems not only create tangible benefits such as enhanced reliability and reduced O&M expense, but also facilitate customer-focused programs to improve fault detection, minimize downtime, and expedite restoration. These projects will also facilitate the integration of DER and enhance grid management, leading to reduced energy losses and increased efficiency, especially during peak load conditions. These benefits are also described in greater detail in the direct testimony of Mr. Whitworth.

2025 OT&S O&M EXPENSE BUDGET

Q. What is the level of O&M expense projected for the OT&S area in 2025?

A. The level of O&M expense for the OT&S area in 2025 is a component of the Electric Delivery budget, which is described in the direct testimony of Mr. Whitworth.

Q. What steps has the company taken to reduce O&M expenses in OT&S?

A. OT&S continuously evaluates effective ways to reduce O&M, including methods such as workflow automation, data driven decision making, and business process optimization.

Q. What is the average number of team members within the OT&S area in 2022 through 2024?

A. The average number of team members within the OT&S department was 197 in 2022, 202 in 2023, and 234 in 2024.

Q. How many team members do you expect to employ in the 2025 test year?

A. The company projects our average number of team members within the OT&S department in 2025 to remain the same as 2024, at 234 team members.

Q. What factors caused the addition of approximately 37 new team members in the OT&S area between 2022 and 2024?

A. The increase of approximately 37 team members between 2022 and 2024 is primarily due to the (1) internal transfer or reassignment of 24 team members to the OT&S department; and (2) hiring of 13 new team members.

A total of seven employees transferred to OT&S from the IT department, along with 11 from Energy Supply and six from the company's RF Controls team. These reassignments were needed to help the OT department carry out its vision and strategy. Additionally, Tampa Electric determined the OT department needed 13 new employees to provide the new skillsets necessary to manage and maintain the operational technology infrastructure. These 13 additions include the following positions:

- Four to perform data strategy, data analytics, and project management.
- Two to perform ADMS job functions.

C7-472

- Three who joined the Meter team.
- Four who joined the Lighting team.

Q. What metrics or analysis did the OT&S department use to identify the need for the approximately 37 additional employees in the OT area?

A. The OT&S department first identified the skills necessary by engaging in communications with industry leaders in the field. We then looked within the company to identify current employees that already had these skills or could be retrained to develop them. The department was then able to determine the number of new employees or "new hires" required and what skillset would be needed.

Q. Do the approximately 37 team members added to the OT&S department between 2022 and 2024 result in any avoided costs or cost savings?

A. As stated above, 24 of the additional employees were transferred from another area of the company, which does not add to the overall number of company employees. This reorganization will allow the company to better use the existing skillsets in a more effective manner. The 13 new Tampa Electric employees that joined the OT&S department bring new skillsets that allow us to achieve the organizational efficiencies and customer benefits that I previously described in my direct testimony.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony describes the company's OT&S department, and the OT&S resources and applications Tampa Electric uses to operate its electric system and provide an outstanding customer experience. I explained the progress made in the OT&S area since the company's last base rate case. I summarized the OT&S department's plans and explained the company's OT&S capital investments and O&M expense. I described the Grid Reliability & Resilience Projects that will be going in service as part of Tampa Electric's Subsequent Year Adjustments for 2026 and 2027. These investments will enable us to provide a more resilient and reliable service to our customers.

Q. Does this conclude your direct testimony?

A. Yes.

C7-474

(Whereupon, prefiled rebuttal testimony of David Lukcic was inserted.)

D5-373

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240026-EI

PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

REBUTTAL TESTIMONY
OF
DAVID LUKCIC

D5-373

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
FILED: 07/02/2024

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

DAVID LUKCIC

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

A. My name is David Lukcic. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or the "company") as Senior Director Operational Technology & Strategy.

Q. Are you the same David Lukcic who filed direct testimony in this proceeding?

A. Yes.

Q. Have your title and duties and responsibilities changed since the company filed your prepared direct testimony on April 2, 2024?

A. No.

Q. What are the purposes of your rebuttal testimony?

A. My rebuttal testimony serves two general purposes.

First, I will address inaccuracies in the direct testimony of witness Kevin Mara, filed on behalf of the Office of Public Counsel ("OPC"), and explain why the Florida Public Service Commission ("Commission" or "FPSC") should authorize including the company's Grid Reliability and Resilience ("GRR") Projects and the Grid Communications Project in the proposed Subsequent Year Adjustments ("SYA").

Second, I will respond to the direct testimony of witness Karl Rábago, filed on behalf of the League of United Latin American Citizens ("LULAC") and Florida Rising, and demonstrate why the Commission should reject his proposal to disallow cost recovery for the GRR Projects.

I. THE GRR PROJECTS ARE PRUDENT AND SHOULD BE INCLUDED IN THE PROPOSED SYA

Q. Does Mr. Mara challenge the necessity or prudence of the proposed GRR Projects in his testimony or otherwise argue that the company should not complete those projects?

A. No. Instead, he argues that the GRR Projects should be recovered in base rates in the test year or in future test years. To illustrate, on page four of his testimony he states that the GRR Projects should be excluded from the company's SYA. Similarly, he argues on page nine that the SYA is "not the proper funding mechanism" for the GRR Projects. As I explained in my direct testimony, the GRR Projects are necessary and prudent investments to meet customer demand, build a resilient grid, and adapt to changes in how our customers use, and sometimes produce, energy.

Furthermore, as I will explain below, Mr. Mara's recommendation that the GRR Projects should be excluded from the SYA is based on an inaccurate assessment of the nature and scope of the GRR Projects, as well as a misunderstanding of which components are included in the company's SYA. My testimony will address these inaccuracies and explain why the GRR Projects should be approved. Tampa Electric's witness Jeff Chronister will address why the GRR Projects are properly included in the SYA from a rate making perspective.

Q. Does Mr. Mara's testimony correctly describe which GRR Projects are included in the company's 2026 and 2027 SYA?

A. No. His testimony includes the following inaccuracies: (1)

In my direct testimony, I described three GRR Projects components that are included within the 2026 and 2027 SYA. Mr. Mara discusses only one of the three components. (2) Mr. Mara inaccurately describes several of the GRR Projects included in the SYA as routine activities to maintain or replace obsolete equipment and argues that these investments should be excluded from the SYA. (3) Mr. Mara inaccurately states that the forward-looking nature of these investments makes them inherently speculative and thus they should be excluded from the SYA. (4) Mr. Mara inaccurately states that the GRR projects included within the SYA, all of which will be in-service by the end of 2026, will not provide value to Tampa Electric's customers until the overall program is complete - by the end of 2030. (5) Lastly, Mr. Mara incorrectly states that none of the GRR Projects have been approved by either the Tampa Electric or Emera Board of Directors at the time of the rate case filing.

The remaining discussion in Section I of my rebuttal testimony will provide additional context and information on the issues I described above.

(1) Clarification on which GRR Projects are in the SYA

Q. On page seven of his direct testimony, Mr. Mara states that the GRR Projects included within Tampa Electric's 2026 and 2027 SYA include Private LTE Implementation, Line Sensor Software, Work Management System ("WMS"), and Distribution Planning Software upgrades. Does this accurately reflect the GRR Projects included within the 2026 and 2027 SYA?

A. No. As I noted on pages 53 through 57 of my direct testimony, there are three components of the GRR Projects that are included within the SYA: (1) the Grid Communication Network, (2) the Customer Information Device Expansion, and (3) the Grid Communication Network Hardware, Work Management, and Control Systems components. The projects noted by Mr. Mara only reflect the third GRR Projects component.

Q. In Table 2, on page 8 of his testimony, Mr. Mara compares information provided by Tampa Electric in response to OPC's Seventh Set of Interrogatories No. 126 to SYA information provided in Tampa Electric witness Richard Latta's direct testimony (now Prepared Direct Testimony of Jeff Chronister Volume II). Based on this comparison, Mr. Mara states that the "budgeted values in these [referring to the PLTE Implementation, Line Sensor Software, WMS, and Distribution Planning Software] systems do not exactly match with the SYAs..." Can you provide any additional clarification on Mr. Mara's perceived misalignment between these two data sources?

A. Yes. Mr. Mara's comparison is flawed for several reasons. First, Mr. Mara's comparison of the company's answer to OPC's Seventh Set of Interrogatories No. 126 with the SYA budgets is incorrect because the interrogatory response was not limited to the components included in the SYA. OPC's Seventh Set of Interrogatories No. 126 asked the company to provide the annual cost by project type for all six components of the GRR Projects. As I previously explained, the company only included some components in the SYA. The company's interrogatory answer accordingly reflects total expected annual capital expenditures for all GRR Projects, regardless of whether they are included in the SYA.

Second, Mr. Mara's Table 2 does not match what is included in the SYA. Table 2 does not include capital expenditures associated with some components included in the SYA, including the PLTE Spectrum (i.e., Grid Communication Network) or Customer Information (i.e., CRB) Device Expansion. Table 2 does, however, include capital expenditures for the Distribution Design Tool and Short-Cycle Work Management upgrade, which are not included in the SYA, as I will discuss in more detail below.

Third, Mr. Mara made an apples-to-oranges comparison between the annual capital expenditure amounts presented in Tampa Electric's answer to OPC's Seventh Set of Interrogatories No. 126 with figures from Volume II of Mr. Chronister's direct testimony. The numbers in Volume II of Mr. Chronister's testimony are not total annual capital expenditures, but rather reflect 13-month average plant in service, which includes both capital and the associated financing costs. As I previously explained, the company's answer to Interrogatory No. 126 provided total annual capital costs.

(2) Clarification on the Description of System Replacements

Q. On page eight of his direct testimony, Mr. Mara characterizes the GRR Projects included within the 2026 and 2027 SYA as "routine type of activities," and adds that these projects include "maintenance and replacement of obsolete equipment." Do you agree with this characterization of the GRR Projects included within the SYA?

A. No. As I stated on page 18 of my direct testimony, the GRR Projects build on Tampa Electric's existing grid modernization strategy and will provide new and enhanced functionality across each of the investments. Overall, the

GRR Projects represent a comprehensive program that will create a "system of systems" with coordination across the six investment domains to improve grid reliability, provide customers with greater access to data to make more informed energy decisions, and enable more efficient and effective operations within Electric Delivery. Specifically, the GRR Projects within the SYA include upgrades to existing systems (i.e., Distribution Planning Software Upgrade), replacement of obsolete systems (i.e., Work Management System), as well as deployment of new systems that do not exist today (i.e., Distribution Design Tool). However, none of these projects are routine maintenance or like-for-like replacements of equipment. Rather, each of the GRR Projects provides new or enhanced functionality that is critical to meet customer expectations and enable the benefits of a modern intelligent grid (e.g., automated FLISR).

Q. On page 10 of his testimony, Mr. Mara characterizes the Grid Communication Network Project as "replacement of an older, obsolete [radio] system" that should be accomplished through the company's test year budget. Do you agree with his characterization of the project and his conclusion?

A. No. The primary purpose of the Grid Communication Network Project is to install a new system that will provide improved cybersecurity, resilience during storms, reliability, safety, and performance benefits. While it is true that the Grid Communication Network Project will replace the existing end-of-life SCADA system, the project will also provide capabilities and capacity well beyond the existing SCADA radio network. These advancements provide the infrastructure to manage the expansion of electric vehicle charging and customer-owned solar generation and lay the groundwork for new functionalities at both the distribution level and the grid's edge. Furthermore, this project is appropriately included in the SYA because it will be completed in 2026 and begin providing value to customers beginning as early as December 2024 when the first ten PLTE towers are completed.

Q. Have other electric utilities installed a PLTE?

A. Yes. Tampa Electric is aware of several peer utilities that have installed, or are in the process of installing, PLTE networks within their service territories including Florida Power & Light (Gulf Region); Southern Company in Alabama, Georgia, and Mississippi; Ameren; San Diego Gas & Electric; Evergy; Xcel Energy; and Lower Colorado River Authority.

Q. On page 12 of his testimony, Mr. Mara argues that the work management system upgrade is an "upgrade of an existing system" that should be included in the company's test year budget and not an SYA. Do you agree with this characterization and recommendation?

A. No. This project adopts an entirely new work and asset management system that will provide significant new functionality including, but not limited to, modern Application Programming Interface ("API") based communications, workforce optimization and analytics, and mobile communication capabilities. The new system will replace the current work management system ("WorkPro") which was initially installed in 1997 and has been out of vendor support for ten years. This project will be completed and in-service by December 2026 and should be included within the SYA.

Q. On page 13 of his testimony, Mr. Mara asserts that the "Distribution Planning Software Upgrades" (referring to the short-cycle work management system, distribution design tool, and system planning model upgrade) represent either upgrades to existing software or replacement of an existing program and claims that the company should recover the costs of these programs through "traditional base rates" and not an SYA. Do you agree with this characterization and recommendation?

A. No. As a preliminary matter, I would like to clarify that these are three distinct systems. First, the investment in the Short-Cycle Work Management System Upgrade is to replace the current PragmaCAD system with a new system to manage and execute emergent or reactive work orders. The company uses PragmaCAD system when responding to equipment failures or other unplanned incidents that impact service reliability (e.g., vehicle hits a pole). The PragmaCAD system is distinct from WorkPro, which is the current system used to generate distribution, transmission, lighting, and substation work orders for planned activities. The current versions of both PragmaCAD and WorkPro are limited in functionality and no longer meet industry standards. The new Work Management system installed through the GRR Projects will better align work management functionality and enable greater consistency for how work is executed across Electric Delivery for both planned (i.e., long-cycle) and emergent (i.e., short-cycle) work and increase operational efficiencies in Electric Delivery.

Second, the Distribution Design Tool Project implements a new, dedicated design tool that Tampa Electric has not previously had. Currently, electric distribution designs are built in the GIS or AutoCAD, both of which offer limited functionality to automate the design process, unlike the Distribution Design Tool. This project will provide significant efficiency benefits and help Tampa Electric design customer projects faster and more effectively.

Third, the System Planning Model Upgrade will upgrade or replace the distribution load flow model (i.e., Synergi) which, in combination with other GRR Projects, including the GIS replacement, ensures that the grid model accurately reflects the distribution system as it grows to include new distributed energy resources.

The Distribution Design Tool and Short-Cycle Work Management Projects are both expected to be in-service in 2027 and were not included in the SYA. The Distribution Planning Software Upgrade (i.e., Synergi replacement) is the only project of the three that Mr. Mara described on page 13 that was included in the SYA. Since this project is scheduled to be completed and in-service by the end of the third quarter of 2026, and since it will significantly improve efficiency, it should be included within the SYA.

(3) <u>Clarification on Forecasted Capital Costs</u>

Q. On Page nine of his testimony, Mr. Mara asserts that GRR

Projects' expenditures should be excluded from the SYA because work on various components of the GRR Projects will continue until 2030, and because the expenditures are "forecasted costs." Do you agree with this recommendation?

A. No. It is true that certain GRR Projects will not be completed until 2030; however, none of these components have been included within the SYA. The GRR Projects included within the SYA will all be in-service by December 2026 and will provide value to Tampa Electric customers prior to the overall completion of the project. For example, once the PLTE system is functional, with the appropriate control schemes in ADMS, and deployment of intelligent switching devices deployed on distribution circuits as well as within the substation, Tampa Electric will be able to test and begin implementation of automated FLISR. The reliability and system benefits for all of Tampa Electric's service territories will then increase as devices are deployed across the entire system.

Additionally, the SYA costs reflect budgeted amounts for the projects based on best estimates and past project experience. If the projects were to run over the amount included in the SYA, those dollars would not be automatically recovered, and the company would need to request cost recovery for those dollars and justify the expense in a future rate case.

(4) <u>Clarification on When Systems Will be In-Service</u>

Q. Mr. Mara asserts that the Grid Communication Network Project and the Line Sensor Software component should be excluded from the SYA because they will enable other technologies that will not "be fully capable" by the end of 2027. Is this statement accurate?

A. No. The benefits of automated FLISR will be functional in certain portions of Tampa Electric's service territory by the end of 2026. As previously stated, the company will begin connecting field devices as early as December 2024 when the first communication tower is completed. Additionally, once the PLTE system is in-service, Tampa Electric will be able to retrofit existing devices to connect devices to this new network, which will provide benefits including enhanced security and speed of communication with field devices.

Q. Will the components of the GRR Projects included in the SYA go into service and begin providing benefits to customers before 2027?

A. Yes.

(5) Clarification on the Status of Project Approvals

Q. On Page nine, Mr. Mara says the GRR Projects should be excluded from the SYA because "none of this project -- in either its sub-parts or its totality - had been approved by either the Tampa Electric or Emera Boards of Directors at the time the case was filed". Is this statement accurate?

A. No. Several foundational components of GRR Projects were already approved at the time of the rate case filing. The Grid Communication Network Project (i.e., PLTE) was approved by the Tampa Electric Board in November of 2023. Additionally, the Capital Leadership Team previously approved certain investments within the Field Devices and Substation domains. The previously approved investments include: (1) a project to implement integrated volt/VAR control ("IVVC") through the installation of IVVC capable capacitor banks, and (2) a project to replace outdated analog circuit breakers and associated electro-mechanical relays within substations with modernized breakers and relays. The investments described above are critical aspects of the GRR Projects and are required to enable further system reliability improvements, including future utilization of automated FLISR. Additionally, the Tampa

Electric Board of Directors have been thoroughly educated on the GRR Projects over time, ensuring informed decision-making and oversight.

Q. Have there been any updates to the approval of the overall GRR Projects since your direct testimony was filed?

A. Yes. The GRR Projects were brought to the Tampa Electric Board of Directors for review and approval on June 11, 2024, and the GRR Projects were approved in their entirety.

(6) Recommendations Based on Mr. Mara's Direct Testimony

Q. Based on the information and arguments presented within Mr. Mara's direct testimony, do you agree that the GRR Projects described in your direct testimony should be excluded from the 2026 and 2027 SYA?

A. No.

Q. What is your recommendation to the Commission regarding the GRR Projects components included in the SYA?

A. I affirm what was stated in my direct testimony regarding the need for, and prudence of, the GRR Projects, and I recommend that the Commission approve all three components of the GRR Projects that were included within the SYA for 2026 and 2027. Those three components are (1) the Grid Communication Network, (2) the Customer Information Device Expansion, and (3) the Grid Communication Network Hardware, Work Management, and Control Systems components.

II. THE GRR PROJECTS ARE NECESSARY AND PRUDENT, AND THE COMMISSION SHOULD AUTHORIZE COST RECOVERY FOR THOSE PROJECTS

Q. On page 51 of his testimony, Mr. Rábago describes the GRR Projects as "unnecessary gold plating." Do you agree that the GRR Projects are unnecessary?

A. No. As I noted in my prior responses to Mr. Mara's statements, the GRR Projects are a continuation of Tampa Electric's grid modernization strategy to improve the reliability and functionality of the Electric Delivery system. The GRR Projects are necessary to meet evolving customer expectations for the electric system to be "always on", while preparing to manage bi-directional power flows at the grid edge. As I noted in my direct testimony, the GRR Projects are designed to address changes to the grid, including increased digitalization and decentralization. Customer adoption of distributed generation, electric vehicles, and battery storage is causing a need for greater grid visibility and new technologies to control bi-directional energy flows. The GRR Projects will provide tangible benefits for customers including, but not limited to, enhanced reliability and reduced O&M expenses. Further, as noted in Tampa Electric witness Chip Whitworth's direct testimony, the GRR Projects are necessary to replace obsolete systems and equipment, as well as meet customer demands for greater reliability, greater access to data, and to adapt to changes in how customers consume energy.

Q. On page 55 of his testimony, Mr. Rábago asserts that the GRR Projects are "destined for quick obsolescence." Do you agree with this conclusion?

A. No. I note that Mr. Rábago does not describe what timeframe he would consider to be "quick obsolescence." Mr. Rábago specifically calls out the PLTE network, which has an estimated useful life of 20 years. I do not consider technology with an estimated useful life of two decades to be destined for "quick obsolescence." Further, the PLTE network is designed to alleviate current communication constraints, as well as prepare for future needs including enhanced cybersecurity and reliability standards. The PLTE system, and the GRR Projects as a whole, will draw on lessons learned by peer utilities, the industry experience of internal Tampa Electric standards and compliance experts, and the knowledge of various external consultants to help implement new systems that are designed with future standards and requirements in mind.

Q. Based on the information and arguments presented within Mr. Rábago's direct testimony, do you agree that the Commission should not allow recovery of costs for the GRR Projects?

A. No. The GRR Projects are necessary, prudent, and will result in tangible benefits for the company's customers.

III. SUMMARY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addressed the statements made by witnesses Mara and Rábago regarding the GRR Projects included within the 2026 and 2027 SYA. I demonstrated that Mr. Mara and Mr. Rábago are incorrect in their assertions that the GRR Projects should be excluded from the SYA. The three GRR Projects components that I describe in my direct testimony will all be in-service by the end of 2026, will provide significant benefits to customers, and should be included within the SYA.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BY MR. MEANS:

Q And, Mr. Lukcic, did you also prepare and cause to be filed with your direct testimony an exhibit marked DL-1, consisting of two documents?

A I did.

MR. MEANS: And, Mr. Chairman, Tampa Electric would note for the record that Exhibit DL-1 has been identified in the Comprehensive Exhibit List as Exhibit 22.

BY MR. MEANS:

Q Mr. Lukcic, did you prepare a summary of your direct and rebuttal testimony?

A I did.

Q Will you please deliver that now?

A I will.

Good morning, Commissioners.

My direct testimony describes the company's Operation Technologies and Strategy Department; the OT resources and applications Tampa Electric uses to operate its electric system; explains the progress made to date in operating technology and strategy since the company's last base rate case.

The testimony summarizes the OTS department plans, and explains the company's OT&S capital investments and O&M expenses.

My testimony also describes the Grid Reliability and Resiliency Project that has been created to address increasing customer expectations, two-way power flows, obsolete systems and equipment, in addition to safety and reliability concerns with the evolving grid.

GRR is a collection of a series of grid modernization projects and upgrades that will deliver maximum value in the most effective -- cost-effective manner.

In addition to addressing the issues above, GRR will also address cybersecurity, introduce operational efficiencies, which will reduce operational expenses, provide fuel savings due to reducing line losses, along with setting the foundation for additional customer programs. The program will go into service as part of Tampa Electric's subsequent year adjustments, for '26 and '27.

My rebuttal testimony addresses why the Commission should authorize the inclusion of Grid Reliability and Resiliency Projects in the company's SYA.

My rebuttal testimony also responds to witness Karl Rabago's proposal to disallow recovery for the GRR projects.

This concludes my summary. Thank you.

MR. MEANS: We tender the witness for cross-examination.

CHAIRMAN LA ROSA: Thank you.

OPC.

MR. WATROUS: Thank you, Mr. Chair.

EXAMINATION

BY MR. WATROUS:

Q Good morning, Mr. Lukcic.

A Good morning.

Q I am going to go ahead and jump right on into questions.

Isn't it true that the company has already been implementing individual components of what you named the GRR project since 2022?

A That is correct.

Q Okay. And the official name is the Advanced Distribution Infrastructure, correct?

A I don't know if I would call that the official name. Although, it has been called both Advanced Distribution Infrastructure and Grid Reliability and Resiliency. The names have been kind of used interchangeably.

Q And you would agree that for many years, Tampa Electric has periodically upgraded and modernized its

distribution network?

A I would say that's fair.

Q And this is what the individual components of the ADI were intended to do when they were forecast in the ordinary course of business, right?

A I don't know that I would say it that way. I think what might be helpful is understanding what GRR is.

GRR was -- evolved out of a series of grid modernization projects. And as such, as we gain through time -- I think Archie talked about it starting in 2018. Through time, what we did is we found a more cost-effective way to execute these projects by looking them in a holistic way. And it really allowed us to find the cost-effective way to deploy them, along with providing the maximum value to the customers. So it was more than a one plus one equals two. It really allowed us to get more, like, a one plus one equals three. And that's how these things kind of evolved.

Q And hasn't the company already invested roughly 21 million in these component projects from 2022 to 2024?

A That's correct.

Q And doesn't the 2025 test year include for an additional 65,871,743 for these component GRR projects?

A That number sounds accurate.

Q In other words, the company has already been accounting for ADI projects consistent with the expectations underlying the rate setting that occurred in the 2021 settlement?

A Could you rephrase the question?

Q Yeah.

So these ADI projects are consistent with the 2021 Settlement Agreement, correct?

A Are consistent with the '21 Settlement Agreement? I am not exactly sure what you are -- I am not exactly sure what you are referring to.

Q Well, these component capital projects were planned for and expected to be deployed between the 2021 and 2024 rate case?

A So GRR hasn't evolved that way. It's not a rate case determined activity. It's a -- again, it's a continuation of grid modernization that really results from the increasing expectations from our customers.

So when we continue to see the grid evolving out underneath us, as customers make choices around photovoltaics and electric vehicle selections, changes the complexity of grid. We look at safety, which Chip Whitworth mentioned, as now that PVs are becoming more prevalent, we are seeing two-way power flow concerns on our grid, and safety concerns for both the public and the employees, in addition to customers' desires for better expectations around reliability and storm resolution.

So it's continuing to methodically address those issues that allow the grid modernization program, first, to develop, but then evolve into the most cost-effective way to deploy it and maximize those benefits. And that's what evolved GRR.

So it's not a rate case determination. It's just the next step in an evolution, continuing to find better ways to manage our grid.

Q Okay. So yes or no, these capital projects were planned for and expected to be deployed in between the 2021 and 2024 rate cases?

A Yes.

Q Okay. And these component capital projects are planned for and expected to be deployed during the test year of the current rate case?

A Yes.

Q Okay. And the costs incurred in 2022 through 2024 are being reviewed for prudence in the next base rate case, or the current one?

A The current one. Uh-huh.

Q Is it fair to say the main dispute between

yourself and OPC's Witness Mara isn't the prudence or the need for these projects that are included in the subsequent year adjustments but, rather, the company's decision to seek separate recovery of them through the subsequent year adjustments?

A I don't want to necessarily speak for Mara. To the best of my understanding, that's his position. From our perspective, there is really four components that are critical that we are asking for in the subsequent year. The first one is the PLTE Spectrum, which is the backbone of communications network. The second one is CRB device expansion, another significant but beneficial cus -- investment to the customers as it relates to -- opens the door to a tremendous amount of additional customer programs, more accurate billing, those kind of issues.

And then you also have the work management system that has been in, you know, for decades, out of support. And that will continue to drive operational efficiencies and O&M expense saving for the customers.

And then the last project is the completion of PLTE back office hardware portion of it. And those final pieces go in in December of 2026.

So, yes, there are substantial investments. They are significant. Most of them are multi-year projects, and we felt that the SYA was a -- was an appropriate mechanism for recovery to help relieve pressure for coming back in for a rate case in some of the out years.

Q And isn't spending on the GRR project components going to continue beyond 2027?

A That is correct.

Q In fact, the company forecasts these GRR spending to continue to at least 2030, correct?

A That's correct.

Q And the company could choose to reprofile the capital, right?

A So it's not a -- it's not a capital spend project, right --

Q Mr. Lukcic, can you please answer the question yes or no and then --

A Then I would have to say no, because these projects are co-dependent. When you sit there and try to drive towards the most effective deployment of capital and to maximize the benefits to the customers, they have to go in in a certain order. So a simple of reorganizing projects, or delaying key components is not an effective way to maximize value to the customers.

Q The company could choose to cancel some of the components that have yet to be implemented, correct?

A It's a possibility, but the company would not.

Q Wasn't the PLTE component the only component specifically approved by the board before this case was filed?

A PLT was definitely approved by the board before this case was filed. There have been several grid modernization projects that have been approved by. I don't know specifically anything else in GRR that has been approved by the board, but the board did subsequently approve this project in June of this year.

Q And is the PLTE component still expected to be in service by 2026?

A The PLTE Spectrum should be deployed and functional in Sep -- August of '25, and then the back office hardware in December of '26. And those are the two components.

Q Isn't it true that one of the criteria used by TECO for seeking to recover what they named the GRR project and the subsequent year adjustments was the project was large enough to have been eligible for AFUDC?

A No. AFUDC collection was not a function for determining what actually was asked for recovery. What we did is, as I alluded to before, we picked the most substantial investments. Some of those qualified for a

AFUDC, some of those did not.

Q Do you remember being deposed in July?

A I do.

Q Do you have a copy of that deposition?

A I do.

Q Can you please go to page 47 of our deposition?

CHAIRMAN LA ROSA: Do we know what -- is that an exhibit?

MR. WATROUS: No. One sec, Mr. Chair.

Commissioners, can you give us a moment to pass out the depositions, please?

CHAIRMAN LA ROSA: Sure. I think we are ready when you are, but just clarify, the witness does have a copy of the deposition?

THE WITNESS: I do. Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

MR. WATROUS: And my apologies, Commissioners, for the delays.

BY MR. WATROUS:

Q Mr. Lukcic, can you please turn to page 47?

A Got it.

Q And you were asked in this deposition: It sounds like you are planning a standard here, that if something improves efficiency, that it's appropriate to

include in the SYA. Am I characterizing that correctly?

Can you please read your answer on line six to 10?

A Okay. Can you state the first part of that question or just however you want to phrase it?

Q Yes.

Isn't it true that one of the criteria used by TECO for seeking to recover what they named the GRR project and subsequent year adjustments was if the project was large enough to have been eligible for AFUDC?

And then the question you were asked in your deposition was: It sounds like you are planning a standard here, that if something improves efficiency, that it's appropriate to include in the SYA. Am I characterizing that correctly?

Can you please read your answer, lines six to 10?

A Yeah. So we -- so a couple of things. I think, one, your -- the assertion that AFUDC was the --

Q Can you please read your answer in the --

A So on my page 47, six to 10 says: Lights in a CRB as an asset, just like meters, along with potentially EVs, PVs, and any kind of other edge type devices.

MR. MEANS: Mr. Lukcic, are you looking at the July 23rd deposition transcript?

CHAIRMAN LA ROSA: Yeah. Make sure we are on the right one.

THE WITNESS: You are talking about the first or the second deposition?

MR. WATROUS: July. My apologies.

MR. MEANS: The second deposition.

The second deposition. I apologize.

Okay. I am sorry. Can you give me the page number again?

BY MR. WATROUS:

Q 47.

A Okay. Which line?

Q So the question I asked was: Isn't it true that one of the criteria for seeking to recover the ADI projects were if it was eligible enough for AFUDC. And in this deposition, you were asked: I mean, it sounds like you are planning a standard here that, if something improves efficiency, that it's appropriate to include in the SYA. Am I characterizing that correctly?

Can you please read your answer from line six to line 10?

A Yes.

So to be clear, what determined to be put in the SYA was, number one, the project going to be completed in that year? And then the second criteria was that the project large enough to have been eligible for AFUDC?

Q Thank you for that.

With regards to the PLTE, isn't it meant to replace the company's current obsolete radio system?

A It -- the other thing I want to do is add is -- you cut me off reading lines six through 10, but I also want to add too: Along with providing benefits to customers.

Q Thank you.

A Okay.

Q So my next question is: With regards to the PLTE, isn't it meant to replace the company's current obsolete radio system? And that is not in the deposition.

A No. No. I am -- ask the question again. I am sorry.

Q With regards to the PLTE, isn't it meant to replace the company's obsolete radion system?

A Yes.

Q And isn't the way the ADI has been stitched together designed to gain a maximum amount of efficiency?

A That's correct.

Q And if you start deviating from that plan, doesn't that create problems?

A It we start deviating from plan, that creates problems.

Q And didn't the company just file with the Commission an adjustment to the ADI to estimate certain elements of the SYA -- or eliminate elements to the SYA?

A The company filed to eliminate the recovery of elements in an SYA, not to eliminate the elements.

Q Okay. How many of the 40 components were removed from your original ask?

A As listed in my opening statement, there were two components.

Q Thank you so much.

MR. WATROUS: Nothing further.

CHAIRMAN LA ROSA: Great. Thank you.

Go to Florida Rising/LULAC.

MS. LOCHAN: Sure. Thank you, Chairman.

EXAMINATION

BY MS. LOCHAN:

Q And good afternoon, slash, morning, Mr. Lukcic.

A Good afternoon.

Q I am going to try to keep this short and not

duplicate efforts. So I will ask a few questions about the private LTE network, but just making sure that nothing that I am asking has already been asked.

When considering the -- I am going to just call it the PLTE, because that might be easier -- TECO also considered the costs of doing a public, slash, fiber network?

A That's correct. Yes.

Q And through these considerations, TECO was looking at other utilities that currently have a PLTE.

A That's correct.

Q In those considerations, are there any other peer utilities that you, for TECO, that use a PLTE?

A I am sorry, ask that again.

Q Are there any other peer utilities in Florida that use a private LTE network?

A FPL does up in the Panhandle, yes.

Q And it's only FPL?

A That's correct.

Q So the majority of the Florida peer utilities do not use a private network?

A Uh-huh. That's correct.

Q Thank you.

And I would like to bring up -- this is FLL-179, or master number F3.3-5842.

Do you recognize this document?
A I do. Yes.
Q And this is a document that a third-party, Burns & McDonnell, used to look at the cost for the private LTE network?
A Yes. They are responsible for entire evaluation.
Q Thank you.
If you scroll down, I think, two or three pages, you will see a piechart.
A I am sorry, there is lag here.
Q I was dealing with that earlier.
A Yeah. Oh, can I scroll? I guess that lag was forever. Okay. Yes, I am there.
Q And this shows the breakdown of the estimate of costs?
A Summary of the 10-year cost, yes.
Q Yeah.
And a huge chunk of it are the LTE devices?
A That is correct.
Q Followed by Spectrum?
A That is correct.
Q Thank you.
I am just making sure that some of the questions were not asked.

Okay. The last document I would like to pull up is FLL-189, which is master number F3.3-6365. And if you can click the hyperlink to the Excel there?

A Okay.

Q So you see the sheet here. These -- this represents different -- I am sorry. One second. This represents different operations projects, correct, and costs associated?

A I am sorry. Different what projects?

Q From operations spending costs.

A Uh-huh.

Q All right. And do you recognize this document?

A I do.

Q Thank you so much.

Those are my questions, Mr. Lukcic. Thank you.

CHAIRMAN LA ROSA: Thank you.

FIPUG.

MR. MOYLE: No questions.

CHAIRMAN LA ROSA: FEA.

CAPTAIN GEORGE: No questions.

CHAIRMAN LA ROSA: Thank you.

Sierra Club.

MR. SHRINATH: No questions.

CHAIRMAN LA ROSA: Thank you.

Florida Retail.

MR. WRIGHT: No questions. Thank you, Mr. Chairman.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions. Thank you.

CHAIRMAN LA ROSA: Staff.

MR. SPARKS: No questions. Thank you.

CHAIRMAN LA ROSA: Commissioners, any questions of the witness?

Seeing none, TECO, I give it back to you for redirect.

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

FURTHER EXAMINATION

BY MR. MEANS:

Q Mr. Lukcic, do you recall a minute ago when Mr. Watrous asked you how many of the 40 projects were removed, and you said two?

A Yes.

Q Is the company seeking cost recovery in this case for 40 GRR projects?

A They are not.

Q How many projects -- GRR projects were originally included in this case?

A For the subsequent year adjustment, there were six, and there are currently four.

Q Thank you.

MR. MEANS: Just one second, Mr. Chairman.

BY MR. MEANS:

Q Mr. Lukcic, do you recall earlier when Mr. Watrous asked you about your deposition transcript?

A I do.

Q And you stated in your deposition that AFUDC was a criteria for inclusion in the SYA, do you recall that?

A I do.

Q Did you make a mistake when you said that?

A In the deposition? Yes.

Q Thank you.

MR. MEANS: No further questions.

CHAIRMAN LA ROSA: Thank you.

Let's move exhibits into the record. TECO.

MR. MEANS: Thank you. We would move Exhibit 22 into the record.

CHAIRMAN LA ROSA: 22 into the record. Any objection? Seeing none, show that entered into the record.

(Whereupon, Exhibit No. 22 was received into evidence.)

CHAIRMAN LA ROSA: OPC.

MR. WATROUS: No exhibits from OPC. Thank you.

CHAIRMAN LA ROSA: Any others from any of the parties?

MS. LOCHAN: Florida Rising and LULAC would like to move Exhibits 639 and 649 into the record.

CHAIRMAN LA ROSA: Any opposition to move in those?

MR. MEANS: No objection.

CHAIRMAN LA ROSA: No objections, show then entered into the record.

(Whereupon, Exhibit Nos. 639 & 649 were received into evidence.)

CHAIRMAN LA ROSA: Are there any other exhibits to move into the record?

Okay. All right. Well, Mr. Lukcic, thank you for being with us today, and you are excused.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN LA ROSA: So I think we are good for a lunch break. It is a few minutes before 12:00, so let's say -- let's say 1:05 -- let's say 1:05 we will reconvene here. Okay, great. Thanks.

(Lunch recess.)

(Transcript continues in sequence in Volume 7.)

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 videotaped 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 30th day of September, 2024.

Debbie R. Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028