BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

REGAN B. HAINES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

REGAN B. HAINES

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

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

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

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

Q. Please provide a brief outline of your educational

background and business experience.

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

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

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

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

A. The purposes of my direct testimony are to: (1) describe the changes to the company's T&D system since our last rate case in 2013; (2) provide details about the company's

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

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

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

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

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

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

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

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

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

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

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

TRANSMISSION AND DISTRIBUTION SYSTEM OVERVIEW AND EVOLUTION

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

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

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

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

The company currently has 216 substations.

Q. What role does safety play in Electric Delivery?

A. Safety is the top priority at Tampa Electric and is

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

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

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

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

throughout their lifecycles.

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

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

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

Finally, we sustain the integrated processes and engagement of our teams through documentation and standardization of technical and business processes and the implementation of supporting operational and information technology systems. Applying Asset Management principles gives us a comprehensive understanding of the condition of our assets and the risks associated with them and allows us to better

identify and prioritize the work that needs to be done. This level of understanding enables us to improve our planning and scheduling of work, lowers the costs and risks of operating our system, and improves efficiency and reliability – all of which promote a good customer experience. Asset Management is described in more detail in the direct testimony of Tampa Electric witness David A. Pickles.

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

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

Q. Please describe the indicators the company uses to monitor

reliability and how they relate to what customers experience.

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

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

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

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

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

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

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

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

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

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

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

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

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

common cause and location of outages.

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

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

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

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

A. This system senses when a transformer trips due to an

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

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

Yes. The Substation Medium Power Transformer Doble Testing program is an example. Asset Management principles require consistent testing of critical assets to ensure they achieve their full life expectancy. We perform Doble testing approximately every five years on all medium power transformers. In the last three years, we detected seven bushing and four lightning arrester issues before they

resulted in a failure. Early detection allowed for the company to plan and coordinate the necessary repairs and outages so that all customers fed from the affected transformers were offloaded to other circuits, saving approximately 60 seconds of SAIDI annually. Using the United States Department of Energy's Interruption Cost Estimate ("ICE") Calculator, this single application of Asset Management principles conferred an economic benefit to our customers of approximately $1.9 million.

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

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

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

For business customers, we are currently ranked in the

first quartile for overall satisfaction and ranked in the first quartile for all drivers of satisfaction, including Power Quality and Reliability.

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

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

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

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

The total amount in rate base projected for our 2022 test year, and reflected in MFR Schedule B-07, includes

transmission plant of $1.16 billion and distribution plant of $3.35 billion, for a total T&D rate base amount for the 2022 test year of $4.5 billion.

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

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

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

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

since 2013.

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

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

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

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

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

outage durations.

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

Q. Were these plant additions prudent when made?

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

FUTURE PLANS FOR TRANSMISSION AND DISTRIBUTION SYSTEM

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

A. Yes. Tampa Electric will need to continue investing in its Electric Delivery system to maintain the level of safety, system stability, and service reliability that our

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

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

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

programs, new rate designs, and provide data directly to customers so they can better manage their electric service.

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

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

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

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

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

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

the mobile load of electric vehicles.

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

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

Advanced Metering Infrastructure ("AMI")

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

A. Our AMI project is one of the cornerstones for our grid modernization strategy and will enable the company to fully

support a “Next Generation” power grid. AMI will transform Tampa Electric's relationship with its customers by delivering the choices and convenience that they have come to expect.

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

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

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

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

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

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

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

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

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

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

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

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

A. We expect the capital portion of the AMI system to cost approximately $242 million, which is reflected in our projected rate base for the 2022 test year. We are

approximately nine months from completion, all major pieces have been purchased, contracts are in place, and we expect the project to come in within budget.

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

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

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

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

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

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

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

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

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

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

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

A. Yes. After our AMI system goes in service, Tampa Electric will continue to incur costs associated with the IT systems and integration of hardware, software, development, security, management, and data analytics, as well as the ongoing maintenance of these systems. Those costs are anticipated to exceed the cost savings gained from the AMI

deployment and result in a net increase in O&M expenses. These increased costs are required to provide the benefits and improve our customer experience.

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

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

OTHER FUTURE ELECTRIC DELIVERY PLANS

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

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

or implemented in the Electric Delivery include:

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

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

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

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

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

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

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

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

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

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

digital experience.

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

2022 CONSTRUCTION PROGRAM AND CAPITAL BUDGET

Q. What are Tampa Electric's projected capital investments

for Electric Delivery in 2021 and 2022?

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

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

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

for smaller T&D additions, maintenance, restoration, and other T&D related capital activities.

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

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

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

Q. You previously explained the company's T&D plant rate base additions from 2013 to 2022, why they were prudent, and that they continue to be used and useful to serve the

company's customers. Would you now please describe and explain the additions to T&D plant rate base forecasted to occur in the 2022 test year?

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

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

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

Some of the major areas and projects planned for 2022 are

described in MFR Schedule F-08 and below with their benefits:

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

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

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

thereby improving reliability and service to our customers.

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

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

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

2022 TRANSMISSION AND DISTRIBUTION O&M EXPENSES

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

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

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

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

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

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

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

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

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

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

Delivery's related O&M expenses.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our Asset Management program has played a critical role in controlling Electric Delivery O&M expenses by ensuring that the right assets are maintained, repaired, or replaced at

the right time to eliminate outages, customer impacts and expensive unplanned maintenance activities. The use of technology has helped control O&M costs. For example, the company has implemented a new call out system, ARCOS, which significantly improved our call out response times, thereby reducing outage times and restoration costs. The company has also upgraded its Field Dispatch software, PCAD, which has provided more capabilities to our troubleshooters, again reducing outage times and restoration costs. In addition, the company has started using drones for transmission inspections, which is less costly than traditional helicopter patrols. Finally, optimizing field crew schedules has allowed for increased productivity and safety while reducing restoration costs.

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

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

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

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

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

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

improvements can be attributed to our implementation of Asset Management Program principles in the Electric Delivery area.

SUMMARY

Q. Please summarize your direct testimony.

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

Electric Delivery's proposed T&D budgets support and align with the company's strategic priorities. Our capital budget includes investments for the transmission, distribution, and substation expansion and upgrades needed to support customer growth, maintain system reliability and resiliency, replace aging infrastructure, improve our customers' experience, and meet our governmental and regulatory commitments. Our 2022 forecasted O&M amounts will support the activities required for system operations and restoration, inspections, maintenance of equipment and computer systems, meter services, and required compliance activities. Electric Delivery's continuous improvement initiatives and cost control measures implemented from 2013 to 2020 have resulted in O&M spending below the expected

levels despite increased costs from newly implemented AMI software, additional Emergency Management support, and higher labor rates and contractor costs that have outpaced inflation due to market conditions and increased demand for a limited supply of utility workers. This is reflected by the T&D O&M expenses for the 2022 test year being $9 million below the Commission's Benchmark.

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

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

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

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
WITNESS: HAINES

EXHIBIT

OF

REGAN B. HAINES

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LIST OF MINIMUM FILING REQUIREMENT SCHEDULES

SPONSORED OR CO-SPONSORED BY REGAN B. HAINES

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B-07	Plant Balances By Account And Sub-Account
B-08	Monthly Plant Balances Test Year-13 Months
B-09	Depreciation Reserve Balances By Account And Sub-Account
B-11	Capital Additions And Retirements
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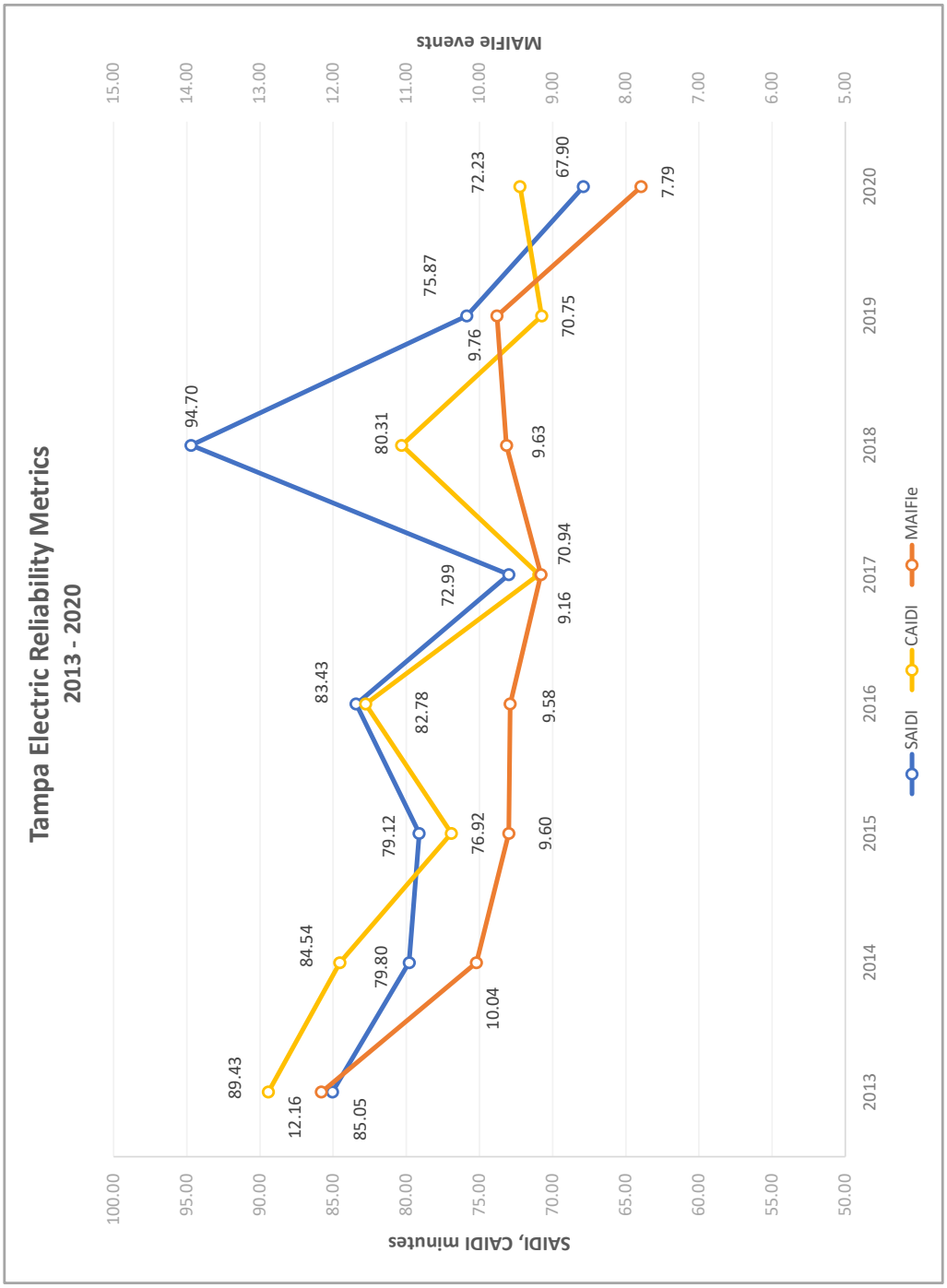
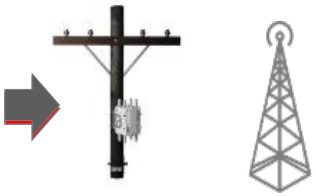
HISTORICAL RELIABILITY INDICES 2013-2020



AMI INFRASTRUCTURE

The Smart Components of AMI

Advanced Metering Infrastructure (AMI) describes the integration of:

Smart Meters	Communications Network	Business Applications	Customer Presentment
			
Smart meters have embedded communication modules that collect and transmit data to and from other smart meters and network devices.	AMI Network Devices, called **Connected Grid Routers (CGRs)** collect data from the meters and transmit that data to the AMI Head End System (HES) via a cellular network.	Several new and existing systems will be used to **communicate, manage and analyze smart meter usage data** , as well as manage smart meter equipment **through the entire lifecycle.**	Customers will have access to tools such as **usage data** , **bill forecasts** , alerts, and **personalized energy saving tips** .

These components work together to transmit energy usage data from smart meters to TEC systems and eventually **to the customer through the web portal and in their monthly bill.**

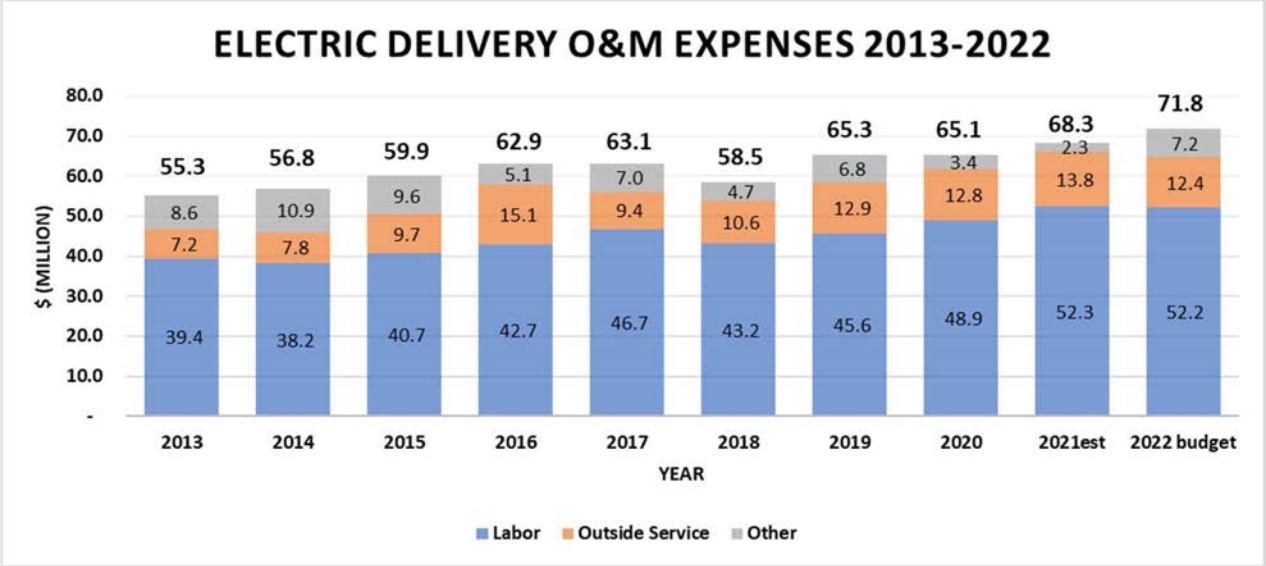
Description	2017	2018	2019	2020	2021	2022	Grand Total
AMI - Communications	1,913,375	1,622,695	816,554	514,706	551,006		5,418,336
AMI - Hardware		1,150,627	181,511	69,869	-		1,402,008
AMI - Software	168,498	19,764,923	31,441,048	32,725,248	26,243,347	172,738	110,515,801
AMI - Adv Metering Infrastructure	2,255,657	7,001,920	48,786,044	42,783,652	8,537,610		109,364,883
AMI - Other		817,239	74,084	486,831	25,000		1,403,155
Subtotal - Capex	**4,337,530**	**30,357,404**	**81,299,241**	**76,580,306**	**35,356,963**	**172,738**	**228,104,183**
AMI - Communications		177,592	267,937	326,486	366,535		1,138,550
AMI - Software		290,891	1,982,389	4,347,547	6,529,637		13,150,464
Subtotal - AFUDC	**-**	**468,482**	**2,250,326**	**4,674,033**	**6,896,172**	**-**	**14,289,014**
Grand Total incl AFUDC	**4,337,530**	**30,825,887**	**83,549,568**	**81,254,339**	**42,253,135**	**172,738**	**242,393,197**
Projects Excluded							
AMP Pilot-AMI Bridge Over	325,616						325,616
AMI Phase 1 Pilot	2,114,424	3,153,958	12,454				5,280,837
	2,440,041	3,153,958	12,454	-	-	-	5,606,453

Transmission and Distribution Capital Investment

($000)

	2021	2022
Distribution	127,834.3	116,013.1
Transmission	20,448.9	32,719.8
Substation	61,628.0	44,463.1
Meter	3,961.0	3,960.2
Lighting	13,783.1	13,797.9
Property Held for Future Use	500.0	500.0
Non Construction (Primarily Technology)	1,924.0	4,000.0
Tools/Equipment/Structures/Vehicle Purchases	9,862.5	7,896.7
Equipment/Vehicle Salvage	2,257.5	1,935.0
Total Recurring Capital	**242,199.2**	**225,285.7**
Big Bend Modernization - Trans/Sub	374.8	-
Grid Modernization	3,000.0	8,599.7
LED Conversion	30,691.4	27,989.1
AMI	35,357.0	172.7
ADMS	8,528.4	1,365.9
Total Strategic/Non-Recurring	**77,951.6**	**38,127.4**
SPP - Distribution	105,651.4	137,657.5
SPP - Transmission	16,480.3	16,502.7
SPP - Substation	-	4,000.0
Total Storm Protection Plan (Clause)	**122,131.7**	**158,160.2**
Grand Total Capital	**442,282.50**	**421,573.35**
Grand Total Capital less SPP	**320,150.77**	**263,413.18**

ELECTRIC DELIVERY HISTORICAL AND PROJECTED O&M EXPENSES



ELECTRIC DELIVERY 2012 O&M Benchmark Comparison

	2012	2022 Budget
T&D O&M expenses	$ 58,406,000	$ 57,035,000
2012 Actual SPP related O&M expenses	$ 11,538,314	
2012 adj O&M less SPP expenses	$ 46,867,686	
Escalation factor using CPI & Customer Growth	1.4103	
2012 actual converted to 2022 $'s using factor	$ 66,099,607	
Comparison	$ 66,099,607	$ 57,035,000
Percentage Variance		**-13.7%**
$ Variance		**$ (9,064,607)**

Energy Delivery
O&M Budget for 2022

Transmission		**2022 Budget Less SPP (000s)**
Operation Supervision & Engineering	$	717
Load Dispatching	$	2,490
Station Expenses	$	1,455
Overhead Line Expense	$	2
Misc Transmission Expense	$	1,090
Rent	$	-
Maintenance of Structures	$	-
Maintenance of Computer Software	$	1,533
Maintenance of Communication Equipment	$	453
Maintenance of Station Equipement	$	1,065
Maintenance of Overhead Lines	$	700
Total	**$**	**9,505**
Distribution		
Operation Supervision & Engineering	$	865
Load Dispatching	$	1,022
Station Expenses	$	1,312
Overhead Line Expense	$	5,093
Underground Line Expense	$	526
Street Lighting Expenses	$	553
Meter Expense	$	4,322
Customer Installation Expense	$	124
Misc Distribution Expense	$	4,744
Rent	$	343
Maintenance of Structures	$	592
Maintenance of Station Equipement	$	2,112
Maintenance of Overhead Lines	$	13,364
Maintenance of Underground Lines	$	2,742
Maintenance of Line Transformers	$	352
Maintenance of Street Lighting & Signal Systems	$	875
Maintenance of Meters	$	370
Maintenance of Miscellaneous Distribution Plant	$	16
Total	**$**	**39,327**
Customers Service		
Meter Reading	$	2,788
Customer Records & Collection	$	2,359
Maintenance & General Plant	$	595
Customer Accts Supervision	$	3
Customer Assistance Expenses	$	15
Customer Service Informational & Instructional Advertising	$	3
Administrative & General Salaries	$	563
Office Supplies & Expenses	$	59
Administrative Expenses Transferred- Credit	$	(316)
Outside Services Employed	$	146
Employee Pensions & Benefits	$	11,949
Regulatory Commission Expenses	$	11
Miscellaneous General Expenses	$	135
Admin & General Rents	$	27
Total	**$**	**18,338**
Other		
Taxes other than Inc Taxes-Utility Operating Inc	$	3,296
Total	**$**	**3,296**
Grand Total	**$**	**71,796**