BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080317-EI

IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

TECO.
TAMPA ELECTRIC

DIRECT TESTIMONY AND EXHIBIT

OF

REGAN B. HAINES

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PREPARED DIRECT TESTIMONY

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

A. My name is Regan B. Haines. My business address is 2200 East Sligh Avenue, Tampa, Florida 33610. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Engineering in the Energy Delivery Department.

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

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

Department. In my current position, I am responsible for directing all activities associated with the designing, engineering, performance analysis, joint use and various construction services for the electric transmission and distribution systems from the generator to the customer's meter.

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

A. Yes. I have testified before the Commission in Docket No. 070297-EI concerning the impact of extreme weather events on the state's transmission and distribution ("T&D") infrastructure and the company's storm hardening efforts.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports Tampa Electric's T&D related capital and operations and maintenance ("O&M") expenses of $218,945,000 and $76,256,000, respectively, for the 2009 test year. These amounts include the costs of implementing Tampa Electric's Storm Hardening Plan approved by this Commission in Order No. PSC-07-1020-FOF-EI, issued December 28, 2007. I will also discuss

T&D operations, system reliability and Tampa Electric's plan for continued cost-effective service to its customers. I will describe the increased federal regulatory challenges the company is facing and recommend a mechanism to recover required transmission additions. Finally, I will discuss and support the company's T&D O&M benchmark comparisons.

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

A. Yes, I am sponsoring Exhibit No. ___ (RBH-1) consisting of seven documents, prepared under my direction and supervision. These consist of:

Document No. 1	List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By Regan B. Haines
Document No. 2	Transmission And Distribution Material, Equipment and Fuel Percentage Price Increases Since 1999
Document No. 3	Transmission And Distribution Capital Investment For 2009
Document No. 4	Transmission And Distribution Related O&M Budget For 2009

Document No.	5	2007 SAIDI Comparison From Southern Company Benchmark Consortium Study
Document No.	6	Florida Investor Owned Utility Historical SAIDI Comparison (Distribution Only)
Document No.	7	Storm Hardening Activity 2009 Projection

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

A. Yes. I am sponsoring or co-sponsoring the MFRs listed in Document No. 1 of my Exhibit No. ___ (RBH-1).

Q. Describe Tampa Electric's T&D system.

A. Tampa Electric's service area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and portions of Polk, Pasco and Pinellas counties. Tampa Electric's transmission system consists of approximately 1,300 miles of overhead facilities, 26,000 poles and 15 miles of underground facilities. The company's distribution system consists of approximately 6,100 miles of overhead lines, 300,000 poles and 7,900 miles of underground lines. Tampa

Electric's transmission and distribution systems are connected through 220 substations throughout its service territory.

COST OVERVIEW

Q. Please describe the expenditures you will be discussing in your direct testimony.

A. The expenditures I will be addressing are T&D related O&M expenses and capital investment. I will describe why these expenditures are required and how Tampa Electric is efficiently balancing short-term maintenance and long-term capital investment in an effort to provide the most cost-effective reliable power to its customers.

Q. What are the main drivers of capital and O&M spending?

A. The need for capital additions as well as O&M expenses are driven by a number of factors. One of the primary drivers is customer growth, which includes the addition of new customers as well as the increased demand requirements from existing customers. Tampa Electric has experienced significant customer growth over the last 16 years and continued growth is projected at a 2.1 percent annual average over the next 10 years. Tampa

Electric's customer base has increased 44 percent since 1991 to 666,354 customers in 2007 and is forecasted to be 679,941 customers by the end of 2009. This growth has occurred within all customer classes. Existing customers also continue to add appliances, televisions, computers, and expand the size of their residences and businesses, which increases demand. This load growth and increase in demand increases the utilization of the T&D system and eventually forces the expansion of the system. As the system increases in size, increased expenditures are required to ensure the safe and effective operation of the system. This increase in demand requires both capital expansion of the T&D system and increases in O&M expenses as well.

A second driver, which is normal and expected by all utilities, is capital and O&M expenses associated with the aging of infrastructure. Florida's population grew by approximately 4.8 million from 1960 to 1980. The number of Tampa Electric customers grew by approximately 168,000 during this time. A significant amount of electric infrastructure was installed to support this increasing population. As a result, some of the infrastructure is now 30 to 50 years old. As the system ages, increased expenditures, both capital and O&M, are required to replace aging infrastructure while providing safe and reliable service to the company's customers.

A third driver, which I discuss later in my testimony affecting both capital and O&M expenses is increases in material and equipment costs as illustrated in my Exhibit No. ___ (RBH-1), Document No. 2. Since 1992, general inflation has increased by 48 percent; steel by 72 percent and concrete by 73 percent.

Two additional drivers for O&M expenses are related to weather and regulatory compliance. The weather, which can vary from year-to-year, creates outages and system outage restoration activities. O&M expenses projected for the test year have been based on a normalized weather year.

Regulatory rules and related compliance costs have increased since 1991. The Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC") both have increased reliability and compliance requirements. The Florida Public Service Commission's storm hardening requirements have also had an impact.

Finally, maintenance spending is required for the company to inspect its growing T&D system on a prudent basis and to correct conditions found during these maintenance inspections before they become detrimental to the system and create operational or safety issues. The company has increased its maintenance activities in order to comply with all requirements of the recent Commission orders related to storm hardening which are further outlined later in my direct testimony.

Q. Please provide an overview of Tampa Electric's T&D related capital and O&M expenditures proposed in this proceeding.

A. Tampa Electric forecasts that it will invest $218,945,000 in T&D related capital and incur $76,256,000 in T&D related O&M expenses in 2009. The Energy Delivery business unit at Tampa Electric is primarily responsible for the T&D related capital expenditures and O&M expenses illustrated in Document Nos. 3 and 4 of my exhibit. The 2009 Energy Delivery capital budget includes the following initiatives: system expansion of transmission, substation and distribution facilities to support customer growth and generation expansion; storm hardening initiatives;

substation circuit breaker replacements; relocations to support road improvements; Automated Meter Reading ("AMR") meter additions; an Energy Management System ("EMS") upgrade project; and outdoor lighting additions.

The 2009 budgeted T&D related O&M costs include those activities required for system operation and restoration; meter reading; vegetation management; inspection programs; and the ongoing maintenance of equipment and computer systems. All projected budgets have taken into account efficiencies and productivity gains the company has achieved through technology and process improvements, which are mentioned later in my direct testimony. These capital investments and O&M expenses are necessary to provide electrical service in a cost-effective, safe and reliable manner while at the same time meeting FERC, NERC, and FPSC requirements.

RELIABILITY

Q. Please provide an overview of the company's reliability initiatives.

A. Tampa Electric focuses on multiple initiatives to cost-effectively maintain and enhance customer service and reliability. First, activities are targeted that will prevent or limit the number of outages experienced by customers and then the company work to reduce the amount of outage time experienced.

The two largest reliability programs the company employs are vegetation management and wood pole inspections. These two initiatives provide the largest benefit for preventing outages before they occur. Additionally, the company performs inspections and repairs to improve T&D circuit reliability, which include circuit thermovision evaluations to detect potential problem areas, condition-based substation maintenance to maintain equipment prior to ineffective operation or failure, underground cable testing to predict failure and pad-mounted transformer inspections and repairs.

Another measure taken by the company to maintain reliable service is through system capacity evaluations. These studies consider the forecasted peak loading demands of customers and identify potential problem areas within the system. This provides the company's engineers with the information needed to develop the most cost-effective alternatives for system expansion.

As a result of these initiatives, Tampa Electric's reliability performance is consistently in the top quartile among utilities according to annual Edison Electric Institute and Southern Company Consortium benchmark reports; see Document No. 5 of my exhibit.

Q. Please describe the primary indices used by the company to monitor system reliability performance.

A. Tampa Electric reviews multiple system reliability indices, but primarily monitors System Average Interruption Duration Index ("SAIDI") and Momentary Average Interruption Event Frequency Index ("MAIFIe"). SAIDI is generally considered a key reflection of operating performance. It indicates the total minutes of interruption time the average customer experiences in a year. SAIDI is calculated by dividing total customer minutes of interruption by total customers served. A significant factor having a direct influence on this index is the severity of the storm season.

MAIFIe defines the average number of times an average customer experiences a momentary interruption event. The MAIFIe index is calculated by dividing the total number of customer momentary interruption events by the total number of customers served. Tampa Electric annually sets reliability goals for both SAIDI and MAIFIe.

Q. Please describe your system reliability performance.

A. Since 2005, Tampa Electric has reduced its SAIDI by almost 10 percent, from 84 minutes to 77 minutes. Document No. 6 of my exhibit shows Tampa Electric's performance relative to the other investor-owned utilities in Florida since 1999. With the exception of the hurricane years of 2004 and 2005, Tampa Electric has consistently had the top or second best SAIDI performance in the state.

Q. What are some additional initiatives that the company has undertaken to improve overall reliability performance?

A. The company has recently made significant improvements to its overall system reliability through various reliability initiatives that will provide benefits in the coming years. This improved performance is a result of a continued focus on first preventing an outage from occurring and then minimizing outage times when they do occur.

For example, the company tracks the performance of distribution circuits that may require performance improvement and has developed a process for the identification and completion of corrective improvements. In 2007, 10 circuits were targeted which resulted in a 42 percent improvement in SAIDI performance for those circuits. Thirty-eight distribution circuits have been identified for this program in 2008.

MAIFIe is also another key measure of system reliability. The identification and elimination of line faults that generate momentary interruptions continues to be a priority and focus of improving distribution reliability for the company because these could eventually lead to lengthier outages in the future. Vegetation management is a major driver for momentary outages. Tampa Electric is transitioning to a three-year tree trim cycle in an effort to minimize these momentary outages.

Another major driver of momentary outages is lightning. Tampa Electric's service territory is located in "Lightning Alley", which has the heaviest concentration of annual lightning strikes in the United States

("U.S.") according to NASA. Replacement of failed lightning arrestors helps minimize lightning's impact. During the company's annual mock storm exercise each spring, team members take the opportunity during circuit patrols to identify lightning arrestors that need replacing.

The company has also pursued reductions to the duration of outages through the development and implementation of process efficiencies and the leveraging of technology. With the implementation of electronic relays on the transmission system, the location of the fault causing the outage is identified to the Energy System Operator ("ESO"). This allows the ESO to isolate the damaged area quickly using remotely controlled pole top switches and return most, if not all, customers back to service even before field team members arrive on site. The ESO also directs the transmission line patrolmen to the problem area to identify what repair will need to be made.

In 2007, the company implemented a distribution circuit restoration project that focused on reducing the duration of feeder outages. This was accomplished through realigning resources available to respond to an outage, isolating the damaged area, restoring service to as many customers as possible prior to repairing the damage, and then installing fault identification devices. This project is further described later in my direct testimony.

All of these initiatives not only help improve system reliability, but they ultimately save costs, which are reflected in all cost projections.

PLANNING PROCESS

Q. Please explain Tampa Electric's approach to planning for expansion of the T&D systems.

A. The objective of Tampa Electric's Energy Delivery System Planning Department is to plan well ahead of customers' needs in order to provide timely, cost-effective and reliable electrical service. Tampa Electric's 10-year demand and energy forecasts, produced by the company's Load Forecasting Department, along with various electrical characteristics are utilized to analyze the future needs of Tampa Electric's T&D system. The planning process identifies when new transmission, substation and/or distribution facilities will be needed to meet customer requirements.

Using the company's forecasted system load, a review of circuit loading, distribution transformer loading and distribution reactive power loading is performed on an annual basis for the next five-year period. Future potential thermal overloads and/or abnormal voltage conditions are also identified. Once it has been determined that additional distribution capacity is required in an area, various alternative projects are created and evaluated for meeting the estimated system growth. Cost estimates are produced for each alternative and the alternatives are then evaluated based on the impact to reliability, voltage, capacity, economics and constructability. Based on these criteria, the most cost-effective viable solution is chosen to accommodate the projected system growth on the distribution system.

The planning criteria for transmission system additions are based on NERC, Florida Reliability Coordinating Council ("FRCC") and other applicable standards. The NERC reliability standards specify transmission system scenarios to be evaluated and the levels of system performance to be attained. The company conducts an annual transmission assessment of the effects of forecasted future load growth over a 10-year period on the transmission system, the need to serve new load areas and/or large new customers, future interconnections with neighboring utilities, integration of new generation facilities and firm contractual transmission service obligations. The changes in system performance due to these factors are simulated and analyzed for the present and future years to identify existing and future system limitations. Alternative solutions to these limitations are then developed, analyzed, and screened based on electrical performance. Viable alternatives are compared for their relative merits with respect to reliability, voltage, capacity, economics and constructability. Transmission facility additions such as a new transmission line are implemented as a result of this process.

As these plans are evaluated, the company also considers the need to acquire land for future substation sites and power line rights-of-way. Growth in general and specific patterns are reviewed to ensure substation sites and power line rights-of-way can be acquired in a timely manner to install the facilities necessary for reliable service. Given the increased efforts presently necessary to acquire land for substations and rights-of-way, it is extremely important to identify and secure the needed rights early before growth makes it very difficult, expensive or impossible. Accordingly, Tampa Electric has acquired property held for future use, which is identified in MFR Schedule B-15, and requests that this property be included in rate base. This investment is both reasonable and prudent.

Q. How do the company's T&D expansion plans become actual projects?

A. Using the results of the planning process, a five-year construction plan and budget are developed which identify the near term projects required to provide reliable service. These plans are also incorporated into the FRCC's planning process, which is described later in my direct testimony.

CAPITAL INVESTMENT

Q. What are Tampa Electric's T&D capital investment plans during 2009?

A. Tampa Electric plans to invest $218,945,000 in T&D related capital in 2009. The company's forecasted T&D capital plans are listed and described in Document No. 3 of my exhibit. This T&D capital investment is required to provide reliable service to customers. In general, these expenditures include capital projects such as substation and switching station construction and upgrades, road widening projects, storm hardening projects, new lighting systems and new T&D circuit construction. Additional capital investments will be made to leverage technology including automated meter reading and various computer software projects.

Q. How have the company's T&D assets grown from 1991 until 2007?

A. The book value of the company's T&D assets in 1991 was $635,774,000. The book value has grown to $1,486,323,000 primarily due to the increase in the number of customers the company serves. The company added over 200,000 customers from 1992 to 2007. The increase in the number of customers has been a primary driver in load growth, which has driven the increase in capital investment.

Q. Are there other reasons driving the need for capital investment besides load growth?

A. Yes. In addition to customer load growth, there is also considerable capital investment required to maintain the reliability of service provided to Tampa Electric's current and future customers. Technology is one area of capital investment used to maintain reliability. Some examples are its outage management system ("OMS"), digital protective relays and fault indicators. Another area of capital investment for reliability is the program necessary to upgrade older equipment.

Q. Please explain the company's need to replace aging infrastructure and to perform system upgrades.

A. Most T&D equipment has a 30-year useful life. Tampa Electric installed a significant amount of T&D infrastructure to support the 168,000 customers that were added from 1960 to 1980. This infrastructure is approaching or is at the end of its useful life, which typically results in increased failures and higher maintenance costs. In order to replace these aging assets prior to failure and to upgrade the system in specific areas to maintain or, in some cases, improve existing reliability levels, capital investments are required.

Tampa Electric plans to target the following system upgrades specifically: various storm hardening improvements to the company's overhead and underground systems; pole replacements; transmission structure inspections and repairs; lightning protection improvements; replacement of obsolete oil-type circuit breakers; replacement of electromechanical meters and substation relays with electronic versions; and physical and cyber security enhancements mandated by the FERC and the NERC. As Tampa Electric's system continues to age and customer growth continues to increase, additional requirements are placed on the system making it imperative that the company keep pace with the service levels that customers expect.

Q. Are there other drivers to the increased cost of capital investment?

A. Yes. Material costs, which have increased at an astounding rate, are another key driver in the company's increased capital spending over the last few years. These high material costs are expected to continue in the future. For example, the price the company must pay for 69/13 kV substation transformers has increased by over 160 percent since 1999. Document No. 2 of my exhibit lists the percentage price increases for typical

T&D equipment experienced in the ten-year period from 1999 to 2008. The significant increases are largely attributable to the infrastructure growth occurring in developing countries causing competition for raw materials.

OPERATIONS AND MAINTENANCE EXPENSE

Q. Please describe what is included in operations expenses.

A. Operations expenses are typically those required to carry out the day-to-day activities associated with operating the T&D system and all activities required to support providing electric service to customers. These include expenses associated with meter reading, meter installations, locating underground facilities, dispatching field team members in response to customer requests, responding to and restoring the system following outages, and switching and re-configuring the company's T&D systems to ensure reliable operations.

Q. Please explain the main drivers for the company's T&D related operations expenses.

A. As mentioned earlier in my direct testimony, the two main drivers are load growth and weather related outages. The company has experienced significant load growth since its last rate case and projects continued growth in demand for the foreseeable future. This continued increase in demand impacts Energy Delivery's activities such as meter reading, meter disconnect and re-connect, and new meter connection activities. Weather related outage activity also has a direct impact on operations expenses associated with restoration activities.

Q. What is included in the T&D related maintenance expenses?

A. Maintenance expenses include activities performed to keep assets in serviceable condition, maintain safety requirements, avert premature failures and manage vegetation growth. They also include activities, which correct or repair non-operable or unsafe conditions on the system as identified through an inspection program or as a result of a storm or other event.

Q. What will be the result of the proposed maintenance spending?

A. During the 2009 test year, Tampa Electric will be increasing maintenance and tree trimming expenditures above current levels and will complete full implementation of inspection and maintenance programs in order to comply with FPSC requirements. The expected result will be improved reliability and service to customers on both a day-to-day basis and following a major storm event. Increasing the level of maintenance and focusing on key programs will enable the company to maintain the reliability standards historically provided to its customers. Tampa Electric's inspection and maintenance programs include: a three-year tree trimming and vegetation management cycle, an eight-year wooden pole inspection cycle, a six-year transmission structure inspection cycle, annual substation inspections, condition based substation preventative maintenance, downtown network inspections and underground system inspections.

Q. Please describe Tampa Electric's vegetation management program and explain why the program's costs are increasing.

A. Tampa Electric is increasing its vegetation management program to establish and maintain a three-year distribution system trimming cycle in order to comply with the Commission's requirements for storm hardening. Tampa Electric's vegetation management program provides a balanced and phased approach toward a three-year tree trim cycle plan to reach the company's desired objectives. The objectives are to improve the quality of line clearance while increasing system reliability. Tampa Electric began ramping up its vegetation management program at the end of 2005, with an emphasis on critical trimming needed in areas identified by the company's reliability based methodology. The company continues its progress toward a three-year tree trim cycle plan and anticipates reaching its goal by 2010.

To ensure the company is implementing the most cost-effective program, Tampa Electric's System Reliability and Line Clearance Departments take into consideration many factors in developing the annual plan, such as multi-year circuit performance data, last trim date and circuit priorities. Various improvements made throughout 2007 resulted in a 15 percent increase in total miles trimmed during 2007 with only a 12 percent increase over 2006 spending.

The proposed 2009 budget for this program is $16,073,000. This is the spending level, plus inflation, that will be maintained going forward. Tampa Electric will continue to review system reliability and all pertinent field and customer information along with its annual trimming plan in order to manage its overall vegetation management program effectively.

Q. Are there other cost drivers for the increased vegetation management costs?

A. Yes. While increased activity is a major driver for cost increases, per unit costs for vegetation management have also grown at a faster pace than inflation. This is primarily due to the competition for resources and increasing contractor rates mainly caused by escalating fuel costs.

O&M BENCHMARK COMPARISON

Q. Have you made a comparison of Tampa Electric's test year T&D O&M budget to the Commission's benchmark?

A. Yes. The comparison for transmission and distribution O&M expenses is shown in MFR Schedule C-37. It demonstrates that the projected T&D O&M expenses for the test year are below the O&M benchmark by $1,064,000. Transmission is $1,721,000 below the benchmark and distribution is $657,000 above.

Q. Why is distribution for 2009 above the O&M benchmark?

A. The 1991 base year included a four-year distribution tree trim cycle, while the 2009 test year includes a three-year distribution tree trim cycle. As I mentioned above, in order to comply with the Commission's storm hardening requirements, the company is transitioning to a three-year tree trim cycle to improve reliability during normal weather conditions as well as major storm events such as hurricanes.

Q. Why is the overall 2009 Transmission & Distribution O&M budget below the Commission's benchmark?

A. As I describe above, Tampa Electric's Energy Delivery team has taken a number of steps to ensure that spending is done in a prudent manner. The company has implemented a number of practices and programs that have improved the overall efficiency and effectiveness of operating and maintaining the T&D system while maintaining SAIDI performance in the first quartile as explained in the "Operational Efficiency and Effectiveness" section of my testimony and shown in

Document No. 6 of my exhibit.

OPERATIONAL EFFICIENCY AND EFFECTIVENESS

Q. What steps has the company taken to manage the company's T&D related capital and O&M expenditures effectively?

A. Tampa Electric's management team has taken a number of steps to ensure that a focus is placed on the right priorities, the proposed budgets are reasonable, and all expenditures are occurring in a wise manner. The company has implemented a number of practices to improve safety and the effectiveness of its workforce, and to create an environment for continuous improvement. These practices have favorably impacted performance in diverse areas of the business including: outage response, workforce utilization, inventory, project management, system protection and meter reading. Significant improvements have also been made to the company's distribution construction standards.

Outage Response

A new OMS was implemented in November 2001. The benefits of this system include a predictive point of outage typically resulting in decreased outage time; increased usage of the interactive voice response system

("IVR") including estimated outage duration and automatic call back when service is restored; and centralized outage information for customer service professionals and field personnel.

Workforce Utilization

In 2003, Tampa Electric hired a consultant to review the planning and scheduling of Energy Delivery's maintenance and construction work. They recommended that the planning and scheduling of work be centralized to give a global view of all resources and work. They also recommended that all work should be planned and scheduled except for true emergency work. This would reduce overall costs and improve on-time service dates due to the efficiencies gained with the process. Beginning in 2004, a new process was implemented and included developing a four-week schedule and releasing work two weeks ahead of time if all resources were available. Emergency work took a priority, but all non-emergency work was scheduled. Key process indicators were developed to evaluate ongoing area performance. In addition to improved customer service, this process change has resulted in many efficiency gains and avoided costs.

Inventory

In May 2003, an initiative was implemented to centralize all major material at one main storeroom and distribute material to the outlying storerooms as needed for scheduled work. A small level of maintenance stock was maintained at each of the outlying storerooms. This change has reduced the amount of duplicate material stored at each service area and resulted in a reduction of inventory levels and an improved inventory turnover ratio. While this initiative has benefited customers by reducing inventory costs, it has not impacted the company's ability to provide excellent customer service.

Project Management

A project management organization was formed in November 2006 to manage large T&D construction projects. This group manages projects from the cost-estimating phase to project completion. The purpose was to improve the execution and overall management of large project work following the identification of project scope. In 2007, this change resulted in the completion of seven out of nine projects within 10 percent of the cost estimate and meeting the in-service date. The seven projects totaled $8,329,500 and the final costs came within $347,370 of the total project cost estimates. The two projects that did not meet the 10 percent criteria totaled approximately $1,826,200 and the final cost came within $146,039 of the total project cost estimates.

System Protection

The main purpose of a protective relay is to sense abnormal conditions on the electric system and then operate the appropriate switching devices to isolate the problem to provide protection to the remainder of the electrical system. In 1998, Tampa Electric purchased its first fully integrated distribution electronic relay. Since that time, the company has installed over 1,400 electronic relays across 48 percent of its T&D system. The benefits of these relays are decreased costs, increased flexibility in system protection, decreased outage times through fault location, reduced maintenance, improved testing cycle time, and a self-monitoring feature that alarms when the relay is not functioning properly. These features have resulted in decreased costs and improved reliability for the company's T&D system.

Automated Meter Reading

In 2003, Tampa Electric initiated an AMR project, which is the application of electronic and communication technology to enable the reading of electric meters remotely. This technology has helped to increase operational efficiencies and to reduce exposure to issues surrounding safety and meters that are hard to access. The 2008 strategy includes the deployment of AMR meters in those areas where high cost reads and the hard to access meters overlap to generate the highest return on investment.

Once an area has been completely saturated with residential AMR meters, there are significant cost benefits. In the areas of Dade City, Plant City and Fish Hawk Ranch in Lithia, there has been a complete conversion of the residential meters to AMR and the cost to read a meter has been reduced from approximately 45 cents per read to 15 cents per read. In general, time needed to read meters in these three areas declined by approximately 58 percent. AMR also lowers the quantity of estimated meter reads. Estimated meter reads averaged 6.7 percent in 2005 but have remained below one percent for the past two years.

The company plans to convert 55,000 residential meters to AMR meters each year at an estimated cost of three million dollars per year. Tampa Electric ended 2007 with 73 meter readers and it is projected that 63 meter readers will be required at the end of 2009. The company has factored in all productivity improvements gained from this initiative into its cost projections.

Construction Standards

Tampa Electric has made many significant improvements to its construction standards since its last rate case. Some of the major enhancements include: 1) standardized overhead triangular construction to minimize life cycle costs; 2) added new class three wood poles to inventory to reduce use of class two poles; 3) converted porcelain horizontal line post insulators to polymer; 4) changed standard arrestor to flying lightning arrestor style on terminal poles; 5) implemented fiberglass guy strains; 6) changed 1/0 stranded cable to solid cable; 7) implemented shorter 1000 MCM reel length; 8) standardized overhead conductor sizes, eliminated 4/0 AL ALCSR; 9) implemented UG jacketed cable; 10) implemented strand filled (Moisture Block) underground cable; 11) eliminated radial (Live Front) pad-mounted transformers; 12) implemented new overhead transformer design with aluminum windings; 13) changed mild steel switchgear enclosures to stainless steel; and 14) changed mild steel single phase transformer enclosure to stainless steel hybrid. These changes have helped manage rising material costs and provided reliability benefits to the system.

Other Process Improvements

Circuit Restoration Initiative - In 2007, Tampa Electric embarked on a mission to reduce SAIDI by reducing distribution circuit outage time. A cross-functional team was put together to investigate the cause and nature of customer outages with a goal of improving reliability. The team discovered that 40 to 50 percent of yearly SAIDI was attributed to entire circuit outages. The result was a project called the Circuit Restoration Initiative. Accordingly, Tampa Electric implemented new guidelines for responding to circuit outages. For example, a guideline was established to have a minimum of two responders for each circuit outage. With the idea of working smarter not faster, two responders are able to patrol and locate problems in half the time. A philosophy of "switch before fix" was also implemented. Upon locating the problem, the first responder initially looks for ways to isolate the problem with switching; this energizes as many customers as possible with alternate feeds, before attempting to make repairs. Although this is not a new concept, with disciplined application, this subtle change has reduced the number of customers impacted while repairs are made.

The company also installed 700 strobe fault indicators on pre-selected circuits. These devices are attached to overhead main feeders at strategic locations. They flash when they sense fault current and the feeder is de-energized. This helps the first responder to quickly locate and isolate the cause of the outage. The company targeted circuits with historically the most problems as well as circuits with sections of lines that are difficult to access.

Preliminary results for the circuit restoration initiative have been outstanding. In 2006, circuit outages experienced were restored with an average restoration time of 48 minutes. In 2007, the average circuit outage restoration time dropped to 38 minutes. With the improvements made, the company was able to reduce the average circuit outage time by 20 percent. The company expects this initiative to play a significant role in reducing SAIDI.

Quicker Crew Call Outs - In 2004, Customer Service replaced the IVR system that provides telephone response for the customer contact center. As part of the IVR replacement, the "outbound dialer" functionality was included in the scope in order to allow for faster, automated call out of crews for restoration work.

Super Crews - This concept was introduced in 2005 to add a more flexible type of crew that could perform both restoration work as well as distribution maintenance work and has provided better resource scheduling flexibility.

Mock Storm Exercise/Faulty Equipment Identification - During the company's annual mock storm exercise each spring, the participants take the opportunity during circuit patrols to identify lightning arrestors and capacitor banks that need repair. The replacement of lightning arrestors and certain capacitor banks will improve reliability. Through this effort, the company not only practices its storm response procedures, but it also identifies equipment needing repair.

Lastly, the company implemented the use of text messaging and emails to alert key team members when a circuit is de-energized. This was accomplished by integrating the EMS and Supervisory Control and Data

Acquisition ("SCADA") systems with the company's email software. Immediately after a circuit outage, the system sends an alert via text message or email to selected local supervisors and managers. This creates an "all hands on deck, firefighter's mentality", to help facilitate a focused and timely response.

Q. How does Energy Delivery ensure operations and maintenance is performed in a timely, efficient and effective manner, and that funds are spent appropriately?

A. Energy Delivery verifies the status of achieving its goals through budgeting, planning and tracking systems and internal business control processes. The company monitors and measures performance through work management, system planning, project scheduling and asset tracking tools in several ways. For example, the key performance indicators are used to report on the performance of distribution, transmission and substation work. Another example is the further delineation of the O&M and capital budgets through the use of an activity-based costing tool, which tracks activities for both production units and costs per unit. Energy Delivery also tracks system performance for outage analysis and input for maintenance and capital spending decisions. Additionally, the company prioritizes the numerous capital projects considered each year and utilizes Primavera software for planning and scheduling many complex capital projects. Finally, Energy Delivery has implemented new financial processes and systems to prioritize, track and monitor spending against its business plans. All of these systems and processes, and the team members that support, develop and use this information, allow Energy Delivery to perform work efficiently and effectively. These activities are aimed at providing quality service to customers at the lowest long-term cost, consistent with meeting the service standards that customers want and deserve.

STORM HARDENING ACTIVITIES

Q. Please summarize Tampa Electric's storm hardening activities.

A. Tampa Electric's storm hardening activities, which include the company's Pole Inspection Program, Ten-Point Storm Preparedness Plan and Storm Hardening Plan, are a multi-pronged approach to enhance the reliability of the T&D facilities.

Pole Inspection Program

To implement Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, Tampa Electric expects to conduct approximately 38,900 distribution and 3,700 transmission wooden pole inspections in 2009 and all inspection related O&M spending is estimated to be $1,610,000 in 2009. Capital replacement and upgrades will cost an estimated $14,789,000 for the same period. This is representative of the pole inspections and replacement the company expects on an annual basis.

Ten-Point Storm Preparedness Plan

Implementation of the Commission's storm preparedness plan in Docket No. 060198-EI, required by Order No. PSC-06-0351-PAA-EI issued April 25, 2006 and approved by Order No. PSC-06-0781-PAA-EI issued on September 19, 2006, will cost an estimated $18,834,000, $17,645,000 in O&M and $1,189,000 in capital, during the 2009 test year. One of the most significant expenses is the implementation of the three-year tree trimming cycle required by the initiative of the Storm Preparedness Plan.

Storm Hardening Plan

Tampa Electric's storm hardening plan was developed in response to Commission Order No. PSC-07-0043-FOF-EU, issued on January 16, 2007, in Docket No. 060172-EU. The Commission has recognized that Tampa Electric's storm hardening plan provides a reasonable, measured approach to storm hardening. The objective of the company's storm hardening plan is to improve system reliability and resiliency during and after extreme weather events. The total storm hardening activities cost projections for the test year, including the previously discussed Pole Inspection Program, the Ten-Point Storm Preparedness Plan is $36,450,000, $19,255,000 in O&M and $17,195,000 in capital, and they are detailed in Document No. 7 of my exhibit.

REGIONAL TRANSMISSION PLANNING

Q. Has Tampa Electric experienced increased federal regulation of transmission reliability since its last rate proceeding?

A. Yes. In the mid-to-late 1990s, FERC began focusing on initiatives that helped enhance wholesale markets and ensure open access to transmission. In its Order 2000, FERC strongly supported the development of regional transmission organizations ("RTO") and encouraged utilities to divest ownership or control of their transmission assets. Tampa Electric, along with the other peninsular Florida investor-owned utilities worked for years on developing GridFlorida.

Q. How has transmission planning in Florida changed over the past few years?

A. A key element of FERC's Order 2000 was the requirement for regional transmission planning and although GridFlorida never materialized, regional transmission planning has remained a priority for Florida. In Order PSC-06-0388-FOF-EI ("GridFlorida Order") from Docket No. 020233-EI, the FPSC determined it would monitor the peninsular Florida utilities and stakeholders' efforts as they continued to find ways to enhance wholesale market opportunities. In its GridFlorida Order, the FPSC stated:

> "Even though we are allowing the Applicants to withdraw the petition, the underlying impetus for examining the feasibility of an RTO still remains a valid concern for the state. Florida would still benefit from laying additional basic framework for wholesale competition, and efficiencies may be gained by making modifications to the current market structure.

Over the past four years, Florida's peninsular utilities and this Commission have conducted a close examination of the current wholesale market and identified several areas where efficiencies may be gained in a cost-effective manner. One of these is already underway at the utilities' initiative, and there are two more that the utilities are investigating. The initiative that is underway is the FRCC Transmission Planning Process."

Q. Please describe the FRCC's transmission planning process.

A. The FRCC has developed a regional "top down" approach to peninsular Florida transmission planning. Prior to its development, transmission planning was primarily performed and studied individually by electric utilities. The individual utility plans would then be aggregated and reviewed by the FRCC for compliance with NERC's planning standards but it was never conducted on a holistic, regional perspective. Since the GridFlorida Order, FRCC has been working on a more comprehensive regional planning model.

The FRCC planning process is intended to develop a regional transmission plan to meet the existing and future requirements of all customers, users, providers, owners and operators of the transmission system in a coordinated, open and transparent transmission-planning environment. The planning process begins with the consolidation of the long-term transmission plans of all transmission owners and providers in the FRCC region. It is a requirement that the long-term transmission plans incorporate the integration of new firm resources as well as other firm commitments. This includes all 69 kV and above transmission facilities. A detailed evaluation and analysis of plans is conducted by utility working groups in concert with the FRCC staff and managed by the FRCC Planning Committee. The evaluations and analysis provide the basis for possible recommended changes to individual system plans that, if implemented, would result in a more reliable and robust transmission system for the FRCC region.

Q. Did the Energy Policy Act of 2005 ("the Act") have an impact on regional planning and reliability?

A. Yes. A significant change due to the Act that impacted the regional planning process was the development of an electric reliability organization ("ERO") with FERC oversight. The Act made compliance with reliability standards approved by FERC mandatory and enforceable, subject to civil penalties. In 2006, NERC was certified by FERC as the ERO for the U.S. The Act also authorized delegation of compliance, monitoring, and enforcement of reliability standards to regional entities such as the FRCC and, in 2007, FERC approved this delegation between NERC and the FRCC. The FRCC is responsible for regulating mandatory planning standards.

Q. What other changes have occurred that affect the regional planning process?

A. Another change that has occurred has resulted in revisions to the FERC Open Access Transmission Tariff ("OATT"). Following the Act, FERC initiated a rulemaking to implement revisions to the OATT to correct perceived shortcomings to FERC's previous orders. This rulemaking process culminated in the issuance of FERC's Order 890 in December 2007, which was the latest step in the evolution of allowing non-transmission owners fair access to transmission service. Order 890 was developed to provide greater specificity to reduce opportunities for undue discrimination. It also established a set of rules to make the planning and use of the nation's transmission system more open and transparent. In particular, Order 890 required the development of a cost allocation methodology for regional transmission expansion. In response, the FRCC developed a regional transmission cost allocation methodology.

Q. Please describe the FRCC cost allocation methodology.

A. A key element in FRCC's cost allocation methodology is that it addresses third-party impacts on transmission facilities; that is, when generation installed on a transmission owner's system overloads facilities on another transmission owner's system. The remedy could require expansion of another transmission owner's system. Third-party impacts have occurred periodically in Florida and have become more pronounced over time, especially since the peninsular Florida system is highly integrated, where changes on one system affect multiple systems.

The FRCC cost allocation methodology divides the peninsular Florida system into cost sharing zones. There are two south zones, one central zone, and three north zones. The protocol is triggered when a third-party impact occurs, an affected owner has requested application of the cost sharing methodology and the third-party impact has been confirmed by the FRCC. For example, assume that a transmission owner's system is in the central zone and the costs for expansion of his system will be shared by the load in the central zone and by the incremental generation in any zone that contributes to the overloading of his system. Under the FRCC methodology, the cost allocation methodology would allocate half of the costs to the load in the central Florida zone and half to the incremental generation that contributes to the third-party impact. While this example has been made simple for illustrative purposes, third-party impacts can be much more complex in terms of identifying costs and benefits. The FRCC methodology represents a framework describing criteria, principles and dispute resolution to guide cost sharing negotiations amongst the parties.

Q. Does Tampa Electric's projected 2009 transmission expenditures include projects that will be submitted for FRCC review?

A. Yes. For 2009, the company has included $68,101,000 in its budget for 230 kV transmission projects. However, given the regional planning process and the dynamic nature of generation and transmission needs for the next five years, it is virtually impossible to predict Tampa Electric's share of expected expenditures accurately. As Florida and the U.S. refine energy policy relative to greenhouse gas legislation, alternative technologies and fuel sources, generation technologies and requirements will be refined accordingly. Even over the past year, clean coal technology has taken a backseat to nuclear and renewable sources. Along with the uncertainty of energy policy, the cost of transmission construction has dramatically increased over the past few years. During the years 2000 through 2002, it cost approximately $700,000 to construct a mile of transmission line. Today that cost could be three times as much due to the higher labor, land acquisition and raw material costs.

Q. In this proceeding, what are you recommending for future transmission expenditures as it relates to cost recovery?

A. Given the need for additional transmission in Florida and the uncertainty associated with future expenditures, I recommend the Commission approve a Transmission Base Rate Adjustment ("TBRA"). The TBRA would allow Tampa

Electric to timely recover its transmission costs associated with those 230 kV and above transmission projects submitted for FRCC review. As I stated above, the company has included $68,101,000 in its 2009 test year budget for such projects, but it is very likely that future expenditures could be even more significant. A TBRA will allow the company to recover its required transmission related expenditures as they are incurred rather than through base rates. In his direct testimony, Tampa Electric witness Jeffrey S. Chronister describes the mechanism in further detail.

LAKE AGNES - CANE ISLAND TAP 230 kV LINE

Q. Please describe the Lake Agnes - Cane Island Tap 230 kV line.

A. The Lake Agnes - Cane Island Tap 230 kV line is made up of two transmission circuits: Lake Agnes - Osceola 230 kV circuit and four miles of the Osceola - Cane Island 230 kV circuit. Tampa Electric owns 25 percent interest in the Lake Agnes - Cane Island Tap 230 kV line. The line is 25.4 miles and connects the Lake Agnes and Osceola substations and includes four miles of transmission line east from the Osceola substation to the tap for the Cane Island substation.

Q. Is the line in Tampa Electric's retail rate base?

A. No. During Docket No. 950379-EI, Order No. PSC-97-0436-FOF-EI, issued on April 17, 1997, the Commission said:

> "It appears that TECO purchased 25 percent of the line primarily to ensure the ability to make wholesale sales to entities such as the Reedy Creek Improvement District ("RCID"). Based on the information available at this time, the company finds that the entire investment shall be assigned to the wholesale jurisdiction."

Q. Are there any reasons this ruling should be reviewed again?

A. Yes. The Lake Agnes - Osceola 230 kV circuit was upgraded in 2008 to meet NERC reliability standards for the bulk electric grid. The Osceola - Cane Island 230 kV circuit is planned to be upgraded in 2010.

Q. Explain the importance of the bulk electric grid to the retail ratepayers.

A. Tampa Electric is interconnected to other utilities via the bulk electric grid. Given the breadth of the Eastern Interconnection from Florida to Canada, west to the Mississippi River, disturbance impacts are minimized due to the solidarity of the grid. The redundancy of transmission grid provides alternate paths for power to flow when there are planned and unplanned outages on the bulk electric grid. Tampa Electric's retail customers also benefit because of its participation in a reserve sharing group ("RSG"). NERC standards require that an entity have enough generation available within 15 minutes to replace the loss of its largest resource. Because of the interconnection, Tampa Electric participates in a RSG that limits the amount of resources that Tampa Electric must maintain to meet this NERC standard. This benefits retail customers from both a cost and a reliability perspective.

Q. Has the Lake Agnes - Cane Island Tap 230 kV line been impacted by the NERC planning standards?

A. Yes. In June 2005, a FRCC transmission assessment of the Central Florida region studied the planned generation additions in the Polk County region and their impact on the I-4 corridor transmission based on NERC planning standards. A Florida Central Coordinated

Restudy of the area was completed June 2006 with the recommendation to upgrade the Lake Agnes - Osceola circuit by June 2008 and the Osceola - Cane Island circuit by June 2011.

Q. Has the Lake Agnes - Osceola upgrade been completed and at what cost?

A. Yes. The upgrade went in service April 24, 2008 at a cost to Tampa Electric of $3,268,000. The Osceola - Cane Island upgrade is expected to cost approximately $900,000. The upgrades and improvements were made to maintain the reliability of the bulk electric grid, which benefits the company's retail customers.

SUMMARY

Q. Please summarize your direct testimony.

A. Tampa Electric forecasts that it will invest $218,945,000 in T&D related capital and incur $76,256,000 in T&D related O&M expenses in 2009. The Energy Delivery capital budget includes system expansion of transmission, substation and distribution facilities to support customer growth and generation expansion, storm hardening initiatives, substation circuit breaker replacements, AMR meter additions and an EMS upgrade project. The 2009 O&M budget includes those activities required for system operations and restoration, meter reading, vegetation management, inspection programs, and the maintenance of equipment and computer systems. These capital investments and O&M expenses are necessary to preserve the company's reliable electric service and to meet the Commission's requirements for storm hardening.

To ensure that the T&D system is reliable, Tampa Electric maintains the necessary capacity and reserves on the system, ensures the quality of the power is acceptable, limits outages from occurring and minimizes the outage time when they occur. The company has recently made significant improvements to its overall system reliability through various reliability initiatives that will also provide benefits in the coming years. Since 2005, Tampa Electric has reduced its SAIDI by almost 10 percent, from 84 minutes to 77 minutes. This improved performance is a result of a concentrated focus on first preventing an outage and then minimizing outage times when they do occur.

To efficiently and effectively manage costs, Tampa

Electric's management team has implemented a number of practices to improve safety, the effectiveness of its workforce, and generally to promote an environment for continuous improvement. These practices have favorably impacted performance in diverse areas of the business: outage response, workforce utilization, inventory, project management, system protection, and meter reading. Significant improvements have also been made to the company's construction standards.

At the same time, the company has experienced additional federal and state regulatory requirements. Tampa Electric, along with the other transmission owners in Florida, expects to invest significantly in the transmission system. Because of the significance of the expenditures and the unpredictable nature of regional cost allocations, a TBRA will serve as an appropriate cost recovery mechanism for future transmission investments.

Overall, Tampa Electric has been able to maintain its system reliability performance and position within the first quartile of comparable peer utilities while remaining below the Commission's O&M benchmark. This represents an appropriate balance between the quality service that customers expect and reasonable costs.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

OF

REGAN B. HAINES

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LIST OF MINIMUM FILING REQUIREMENT SCHEDULES

SPONSORED OR CO-SPONSORED BY REGAN B. HAINES

MFR Schedule	Title
B-11	Capital Additions And Retirements
B-13	Construction Work In Progress
B-15	Property Held for Future Use - 13-Month Average
C-8	Detail of Changes In Expenses
C-9	Five Year Analysis - Change In Cost
C-33	Performance Indices
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C-37	O&M Benchmark Comparison By Function
C-38	O&M Adjustments By Function
C-39	Benchmark Year Recoverable O&M Expenses By Function
C-41	O&M Benchmark Variance By Function
F-8	Assumptions

TAMPA ELECTRIC COMPANY
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Transmission & Distribution
Material, Equipment & Fuel Percentage Price Increases Since 1999

Description	Percentage Increase
Single Phase Overhead Transformer - 25 KVA	59%
Single Phase Overhead Transformer - 37 KVA	85%
Single Phase Overhead Transformer - 50 KVA	48%
Single Phase Overhead Transformer - 75 KVA	60%
Single Phase Padmounted Transformer - 25 KVA	139%
Single Phase Padmounted Transformer - 37 KVA	123%
Single Phase Padmounted Transformer - 50 KVA	113%
Single Phase Padmounted Transformer - 75 KVA	90%
Concrete Pole - 35 FT	25%
CCA Wood Pole - 45 FT Class 2	25%
Concrete Pole - 75 FT Class H1	43%
Concrete Pole - 85 FT	35%
Overhead Conductor - 336 MCM ACSR - 1000 FT	99%
Overhead Conductor - 954 MCM ACSR - 1000 FT	66%
High Pressure Sodium Lamp - 400W	40%
High Pressure Sodium Lamp - 100W	47%
28 MVA 69/13kV Substation Transformer	163%
SOURCE: Tampa Electric Company Purchasing Department	
Gasoline(1)	230%
#2 Diesel Oil(1)	289%
Crude Oil(1)	649%
(1) U.S. Energy Information Administration	
Copper(2)	552%
Carbon Steel(2)	87%
Aluminuml(2)	109%
Zinc(2)	222%
(2) U.S. Department of Labor - Bureau of Labor Statistics "www.bls.gov"	

Transmission and Distribution
Capital Investment for 2009

		($000s)
Blankets		
Distribution	$	73,817
Transmission		11,965
Lighting		11,734
Substation		4,926
Metering		5,237
Vehicles		230
Office		71
Telecom		105
Total Blankets	**$**	**108,085**
Specifics		
Transmission	$	9,160
230kV Transmission		68,101
Distribution		17,387
Road Widening		2,274
Non-Construction		9,238
AMR Meters		3,500
PHFFU		1,200
Total Specifics	**$**	**110,860**
Total Capital	**$**	**218,945**

Transmission & Distribution
Related O&M Budget for 2009

FERC	Transmission	($000s)
560	Operation Supervision and Engineering	$ 694
561	Load Dispatching	2,086
562	Station Expenses	925
565	Transmission of Electric by Others-Operation	372
566	Misc Transmission Expenses	2,013
567	Rents	29
569	Maintenance of Structures	2,813
570	Maintenance of Station Equipment	1,600
571	Maintenance of Overhead Lines	2,895
573	Maint of Misc Transmission Plant	577
Total		**$ 14,004**

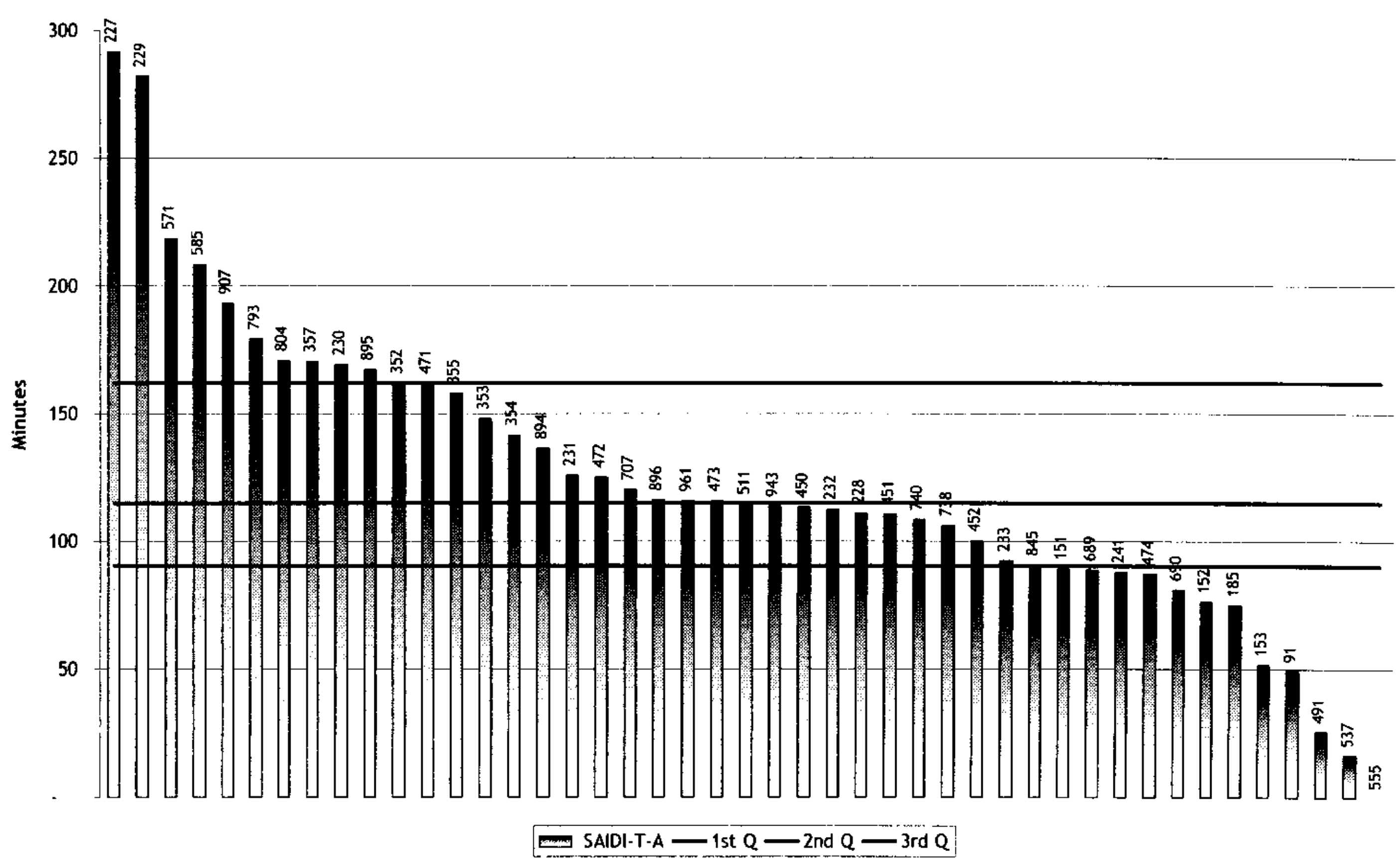
FERC	Distribution	
580	Operation Supervision & Engineering	776
582	Station Expenses	1,013
583	Overhead Line Expenses	120
584	Underground Line Expenses	16
585	Street Lighting & Signal Sys Expenses	380
586	Meter Expenses	4,043
587	Customer Installation Expenses	4,258
588	Misc Distribution Expenses	13,564
589	Rents	529
590	Maint Supervision & Engineering	81
592	Maintenance of Station Equipment	2,588
593	Maintenance of Overhead Lines	24,689
594	Maintenance of Underground Lines	3,660
595	Maintenance of Line Transformers	399
596	Maint of Street Lighting & Signal Sys	2,406
597	Maintenance of Meters	604
Total		**$ 59,127**

FERC	Customer Service	
902	Meter Reading Expenses	3,124
Total		**$ 3,124**

Grand Total		**$ 76,256**

2007 SAIDI Comparison from Southern Company Benchmark Consortium Study

Tampa Electric Company (No. 185)



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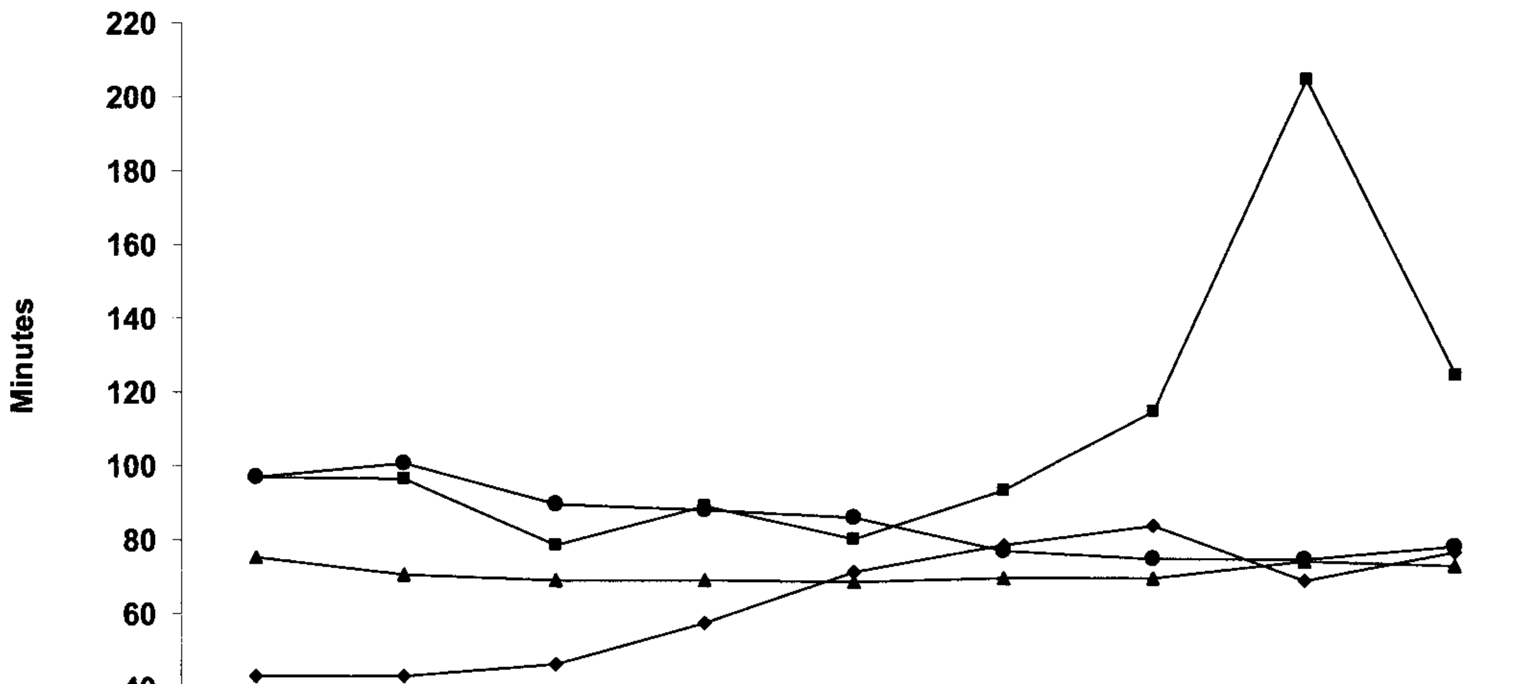
Florida Investor-Owned Electric Utility Historical SAIDI Comparison (Distribution Only)

1997 – 2007



	1999	2000	2001	2002	2003	2004	2005	2006	2007
Gulf	96.9	96.5	78.6	89.2	79.9	93.3	114.9	205.0	125.0
PEF	97.0	100.6	89.7	88.0	85.8	77.0	74.6	74.8	78.3
FPL	75.1	70.3	69.1	68.9	68.2	69.7	69.6	74.3	73.2
TECO	43.0	43.4	46.1	57.2	70.9	78.4	83.9	69.2	76.8

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Storm Hardening Activity
2009 Projections

Storm Hardening Initiatives	O&M ($000s)	Capital ($000s)	Total ($000s)
1) Vegetation Management - Distribution Circuits:			
Planned	$ 14,906		
Unplanned	1,167		
Vegetation Management Subtotal	**$16,073**	**$0**	**$16,073**
2) Audit of Joint-Use Attachment Agreements	218		
3) Transmission Structure Inspection Program:			
Transmission Line O&M	856		
Transmission Line Capital		1,108	
Transmission Substation	278		
4) Collection of Detailed Outage Data (OH vs. UG)		81	
5) Other 10-Point Plan Activities	220		220
Ten-Point Storm Prepardeness Plan Subtotal (Items 1-5)	**$17,645**	**$1,189**	**$18,834**
6) Pole Inspection & Change-Out Program:			
T&D Pole Inspections	1,514		
Distribution Pole Change-Outs		3,932	
Distribution Pole Reinforcements		511	
Transmission Pole Change-Outs		8,460	
Comprehensive Loading Analysis	96		
Change-Outs due to TEC Loading		1,886	
Pole Inspection Program Subtotal	$1,610	$14,789	$16,400
7) Targeted Critical Facilities / Mitigate Flood Damage:			
Port of Tampa		530	
Downtown Network		105	
Interstate Crossings - Distribution		581	
Critical Infrastructure Subtotal	**$0**	**$1,217**	**$1,217**
Total	**$ 19,255**	**$ 17,195**	**$ 36,450**