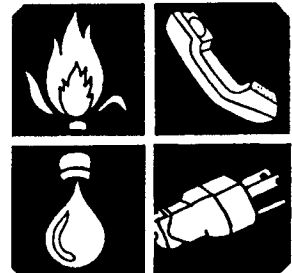


Review of
Electric Service Quality of Florida
Investor-Owned Utilities
Florida Public Utilities Company

March 2005

By Authority of
The State of Florida for
The Public Service Commission
Division of Competitive Markets and Enforcement
Bureau of Regulatory Review



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1.0 EXECUTIVE SUMMARY

1.0 Executive Summary

1.1 Objectives

This management review of Florida's five electric Investor-Owned Utilities (IOU's) was conducted on behalf of the Florida Public Service Commission (FPSC), by the Bureau of Regulatory Review (BRR). The review was requested by the Division of Economic Regulation, in an effort to learn more about each company's efforts to improve distribution and transmission service quality and reliability during the period 1999-2004. The purpose of the management review was to document utility data and operating changes such as company restructuring, increased company use of outsourcing, and changes within FPSC rules.

The review objectives were to:

- ◆ Document and evaluate the corporate philosophy, company organizational structure, operational procedures, monitoring and measurement systems, operational processes, and company philosophies and capabilities impacting electric service quality and reliability.
- ◆ Document and evaluate electric utility activities and programs for distribution and transmission facilities during the period 1999-2004.

1.2 Scope

This review focused on distribution and transmission procedures, processes, systems, programs and activities aimed at maintaining and improving service quality and reliability. The review encompasses the period 1999-2004 and the company reliability results, programs and improvement efforts during that period. BRR staff considered both actual and planned company activities relevant to determining whether company service quality and reliability declined over the period 1999-2004. Staff focused on the following data:

- ◆ FPSC-received customer complaints
- ◆ Company-received customer complaints
- ◆ Company internal management reports
- ◆ Annual FERC Form-1 filing data
- ◆ Annual Reliability Reports filed with the FPSC
- ◆ Company-monitored reliability data
- ◆ Customer satisfaction surveys
- ◆ Company property damage claims

1.3 Methodology

During the review, BRR staff analyzed reliability performance indices and trended company performance during the review period. Staff also requested and reviewed company

documents pertaining to Florida Public Utilities Company's (FPUC) distribution and transmission improvement programs and activities. In-person and teleconference interviews were conducted with company employees to better understand procedures, processes, systems, and improvement efforts. Particular attention was paid to program objectives, measurements, budgets, performance results, and changes in utility practices and philosophies that may have impacted service during the period or may have future impact upon service quality and reliability.

1.4 Overall Opinion

The data examined by BRR staff during this review show the company's reliability indices have fluctuated during the period 1999-2004 with an overall declining trend. BRR staff believes this data along with the finding in the review signals a decline in the level of service reliability received by company customers during the period.

Additionally, BRR staff identified five conditions impacting company reliability that require additional company attention and action. These conditions include the following:

- ◆ FPUC electric reliability performance has declined during the period 1999-2004
- ◆ FPUC electric divisions operate autonomously, which creates operating inefficiencies and hinders improved service reliability
- ◆ Consolidated written FPUC operating and maintenance procedures are needed
- ◆ Consolidated written FPUC goals and objectives for improving service reliability are needed
- ◆ Written FPUC record retention procedures and standards are needed

Each of these conditions and staff's improvement recommendations are further discussed in Chapter 4.0 Conclusions.

2.0 BACKGROUND AND PERSPECTIVE

2.0 Background and Perspective

2.1 Service Quality Reporting

Since the inception of electric utility regulation, the ability to measure company performance, service quality, and service reliability has been of foremost concern. Performance measurement is essential to assess the company's ability to successfully provide acceptable service levels. Service quality and reliability standards and measurements are required to ensure that company facilities meet engineered standards and expectations and that service quality and reliability are maintained or improved.

Measuring service quality and reliability has gained in importance over the years. Changing technology has improved company measurement capabilities and has increased the levels of detail and accuracy of reliability reporting. As companies upgrade their procedures, policies, systems and processes, measurement capabilities will continue to improve.

2.1.1 Previous Service Quality Reviews

The Bureau of Regulatory Review (BRR) has completed two prior service quality reviews at the request of Commission staff. Florida Public Utilities Company was not included in either of the previous reviews. The first review, which was completed in December 1997, examined Florida's four major electric utilities' distribution procedures, processes, and systems related to service reliability. In its report, staff concluded that service quality and reliability had declined at two of the major investor-owned electric utilities. Staff recommended that Florida Power Corporation and Florida Power & Light Company develop and implement service quality improvement programs, which the staff would later review.

The second service quality review, completed in November 2000, was a follow-up review of the two companies identified in the initial audit as having declines in service quality and reliability. Staff efforts concentrated specifically on the improvement programs designed and implemented by Florida Power Corporation and Florida Power & Light and the expected improvements in measurement indices. The other two utilities included in the initial review were not reexamined during the 2000 review.

2.1.2 Importance of Service Quality and Reliability

In modern life, electric power has become an essential service to consumers. Residential consumers rely on electric service to light their homes, to cool and heat them, and for many other uses. Commercial and industrial consumers rely on electric power for many of the same reasons and additionally to light commercial signage, to power security systems, to power computer equipment, and to power manufacturing equipment.

The demand for electric power has continued to increase over time as new consumer products have reached the marketplace, business operations and applications have changed, and industrial/manufacturing processes and improvements have been introduced. Frequent power interruptions became a greater problem with the advent of personal computers. Business prosperity and growth also increase demand and dependence upon electricity. As

commercial/industrial consumers add to existing locations, open new locations, and improve manufacturing processes, their demand for electricity continues to increase. Updates to manufacturing processes and equipment often will also change power quality requirements. Increased demand not only brings greater consumer expectations for reliable electric service, it brings higher expectations for electric service quality. Electric reliability relates to the provisioning of service, while electric quality relates to the level of service provided and can be impacted by increased demand.

2.2 FPSC Standards for Service Reliability

Chapter 25-6 of the Florida Public Service Commission (FPSC) Electric Service Rules provides the regulatory framework for electric public utilities operating under the jurisdiction of the Commission. The ten part rule provides instruction for electric utility operations and guidance in topics such as General Provision, Records and Reports, General Management Requirements, and Accounting Reports. These rules also provide general service provisions and reporting responsibilities for electric utilities operating within the state of Florida. The following sections describe the FPSC Electric Service Rules related to customer complaint reporting, recording of outage data, and reporting of electric service reliability.

2.2.1 FPSC Rule 25-6.021 Customer Complaint Reporting

Chapter 25-6, Part II, Records and Reports, Section 25-6.021 of the FPSC Electric Rules requires electric utilities to keep a record of all complaints received by the company. The utility must record specific information regarding the complaint, including the complainant's name and address, the date the complaint was received, the nature of the complaint, the results of any investigation, the disposition of the complaint, and the date of the complaint disposition. This rule is important because it provides for standard recording of customer complaints received by the company. Records of customer complaints are periodically reviewed by FPSC staff to evaluate the levels and types of complaints recorded at the company level. In addition, consumer complaints are also submitted directly to the Commission. Staff analysis of complaints received by FPSC and company-recorded complaints is discussed in Section 3.9.

2.2.2 FPSC Rule 25-6.044 Continuity of Service

Chapter 25-6, Part IV, General Service Provisions, Section 25-6.044 of the rule requires each electric utility to keep a record of system reliability and continuity of service data, customer service interruption notices, and other outage data. The utility must record each outage event as planned or unplanned and identify the origin of the outage such as generation, transmission, transmission substation equipment, or distribution equipment. The rule calls for each utility to determine the cause of each outage and record it in a standardized manner throughout the utility. The rule also requires that each utility record the date and time of the outage event and the number of service interruptions for the event. Distribution and Transmission outages and coding are discussed in Section 3.4. The Trouble Reporting and Repair processes are discussed in Section 3.5.

2.2.3 FPSC Rule 25-6.0455 Annual Distribution Service Reliability Reporting

Chapter 25-6, Part IV, General Service Provisions, Section 25-6.0455 requires each utility to file an annual Distribution Service Reliability Report with the Commission prior to March first of the following year for the preceding calendar year. This report provides specific performance measurement indices representing the average system and customer outage frequency and duration during the calendar year. The Distribution Service Reliability Report also provides outage data for the utility's three percent of primary feeders with the highest number of feeder breaker interruptions during the calendar year.

2.2.4 FPSC Rule 25-6.046 Voltage Standards

Chapter 25-6, Part IV, General Service Provisions, Section 25-6.046 requires each utility to adopt standard nominal voltages conforming to modern usage that may be required of its distribution and transmission system in its entire serving area or for each district in its system. This rule also requires the voltage at the point of delivery shall not exceed a specific percentage above or below the standard voltage adopted. Voltage standards are discussed further in Section 3.3.

2.2.5 FPSC Rule 25-6.047 Constant Current Standards

Chapter 25-6, Part IV, General Service Provisions, Section 25-6.047 requires each utility supplying constant current street lighting circuits to furnish, as is practicable, the rated current so that it does not vary more than four percent below or above the rated current of the circuit. The rule also states that the utility will check the equipment supplying the constant current output at least once a year and adjust the current if necessary. Constant current standards and practices are discussed further in Section 3.3.

2.3 FPSC Standards for New Electric Construction and Grounding

Chapter 25-6, Part III, General Management Requirements of the FPSC Electric Rules provides utilities general standards for the construction of new electric utility distribution and transmission facilities throughout the state. Part III also provides instruction for inspection of electric utility plant facilities and grounding of primary and secondary distribution circuits. The following sections further describe FPSC Electric Service Rules related to new distribution and transmission construction, utility plant inspections, and service grounding.

2.3.1 Rule 25-6.034 Standard of Construction

This rule states that the electric utilities shall construct, install, maintain, and operate facilities in accordance with generally accepted engineering practices to ensure continuity of service and uniformity in quality of service. The rule incorporates American National Standard Code (ANSI) for electricity metering and requirements, terminology, and test code for instrument transformers as reasonable and good standards of practice. The rule provides that a utility in compliance with the provisions of these publications, and variations approved by the Commission, are deemed to have facilities constructed and installed in accordance with generally accepted engineering practices.

2.3.2 Rule 25-6.0345 Safety Standards for Construction of New Transmission and Distribution Facilities

The Commission Safety Standards rule incorporates ANSI safety standards published in August 2001 as the applicable safety standards for transmission and distribution facilities under the Commission's safety jurisdiction. Each public electric utility, rural cooperative, and municipal electric system must comply with these standards for new construction of transmission and distribution facilities. Each of these utilities is also required to report all electric work orders completed by the utility, or its contractors, at the end of each quarter of the year. In the quarterly report, each utility is required to identify all transmission and distribution facilities subject to the Commission's safety jurisdiction and certify that they meet or exceed applicable standards. In addition, compliance inspections are to be completed by the Commission on a random basis or as appropriate.

2.3.3 Rule 25-6.040 Grounding of Primary and Secondary Distribution

This rule requires each utility to effectively ground the neutrals of all its multigrounded distribution circuits to render them reasonably safe to person and property. Electric utilities must conform to applicable provisions of the publications listed in Rule 25-6.034(2) to ensure the system is grounded to meet the requirements of this standard.

A perspective of Commission rules related to electric service quality and reliability reporting, continuity of service, standards for new transmission and distribution construction, grounding and voltage requirements, safety reporting requirements, and customer complaint reporting should improve the overall understanding of the remaining chapters of this report. These Commission Electric Rules provide the standards to which all electric utilities operating in the state of Florida are measured for the provisioning of safe, reliable, and quality electric service.

3.0 FLORIDA PUBLIC UTILITIES COMPANY

3.0 Florida Public Utilities Company

3.1 Company Profile

Florida Public Utilities Company (FPUC) provides natural gas, propane, and electricity to customers within Florida. The company is the smallest investor-owned electric provider within the state. The company's corporate office is located in West Palm Beach, Florida, with electric division offices located within each geographic service area. Electric operations for the Northwest division are based in Marianna, Florida, and the Northeast division office is based in Fernandina Beach, Florida.

3.1.1 Organizational Structure

Due to geographic and infrastructure differences, FPUC's two electric divisions have been run as separate operations. Each division is headed by a Division Director, reporting directly to the Senior Vice President and Chief Operating Officer in the West Palm Beach corporate office. Each Division Director oversees a local staff of operations employees. The Northwest Division Director oversees 36 employees. The Northeast Division Director oversees 45 employees; 35 within the electric unit and 10 within a propane unit. **Exhibit 1** shows the corporate organization of the company, and **Exhibit 2** shows the organization of the two divisions.

In the 2004 FPUC rate case before the Commission, the company requested the rate base for both divisions be combined as the company was consolidating the efforts of its electric divisions. While the rate base was combined, the two divisions still operate as two separate divisions. In a response to a staff document request, the company states that "additional efforts are underway to continue to standardize many operating practices" within the divisions. The company does not have immediate plans to combine the management functions in these geographically separate operating areas.

Along with the Division Director, each division has an Electric Operations Manager, an Engineering Manager, and a Customer Service Manager who oversee the three departments within each division. Each division is organized under a similar structure, with approximately the same number of associates within each of these three departments. The Electric Operations Manager has oversight of the linemen and repair servicemen, along with managing the daily operations and maintenance activities for the division. The Engineering Manager oversees engineering staff and maintains the overall system design. The Customer Service Manager oversees the customer service personnel and the meter readers.

3.1.2 Operational Characteristics

FPUC purchases power on the wholesale market from Gulf Power Company and the Jacksonville Electric Authority to serve its customers. The Northwest division services approximately 12,528 customers, over a mostly rural 90 square mile service area. This division services part of the Florida panhandle, with customers in Calhoun, Jackson, and Liberty counties. Gulf Power transmission facilities deliver power to the Northwest division through five

substations tied into FPUC's distribution system. The Northwest division distribution system consists of 16 primary feeders with a combined length of approximately 107 miles.

Florida Public Utilities Company Corporate Electric Division Profile

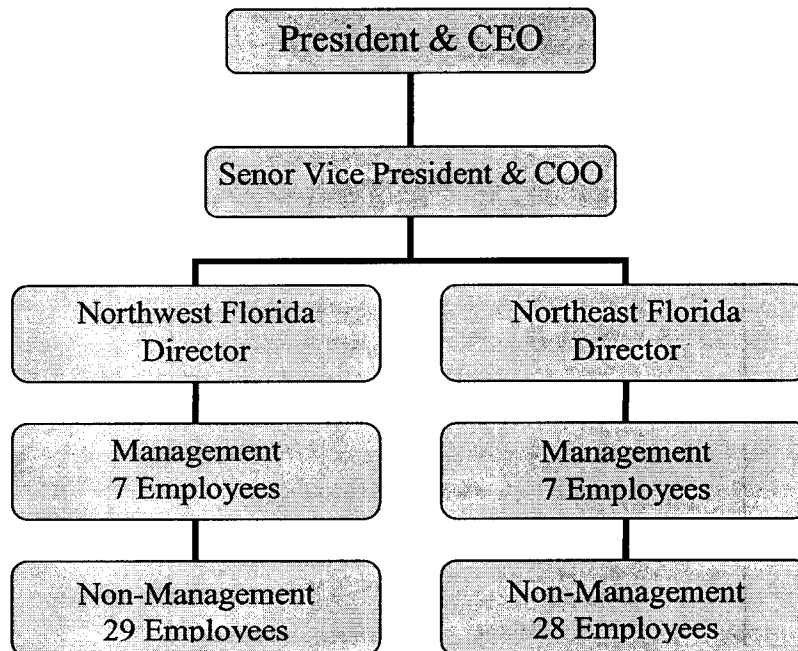


EXHIBIT 1

Source: Document Request 1.1

**Florida Public Utilities Company Electric
Division Level**

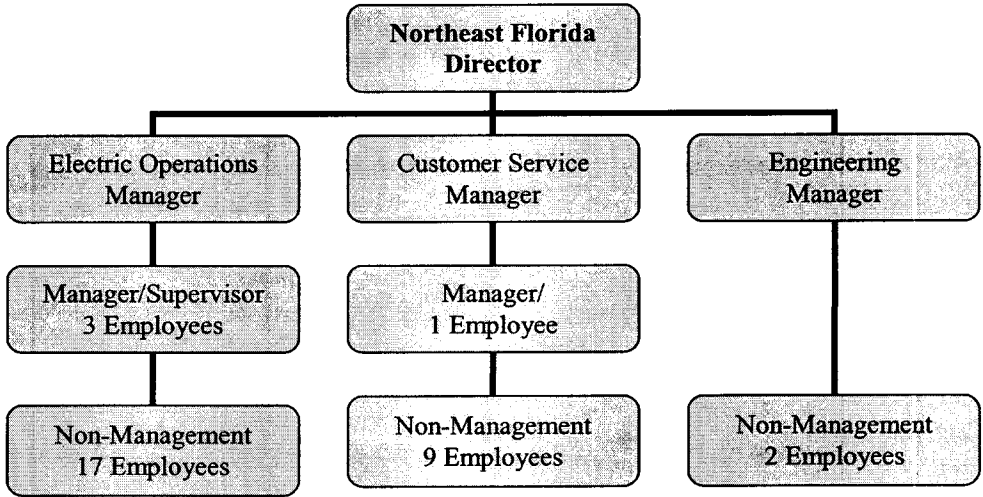
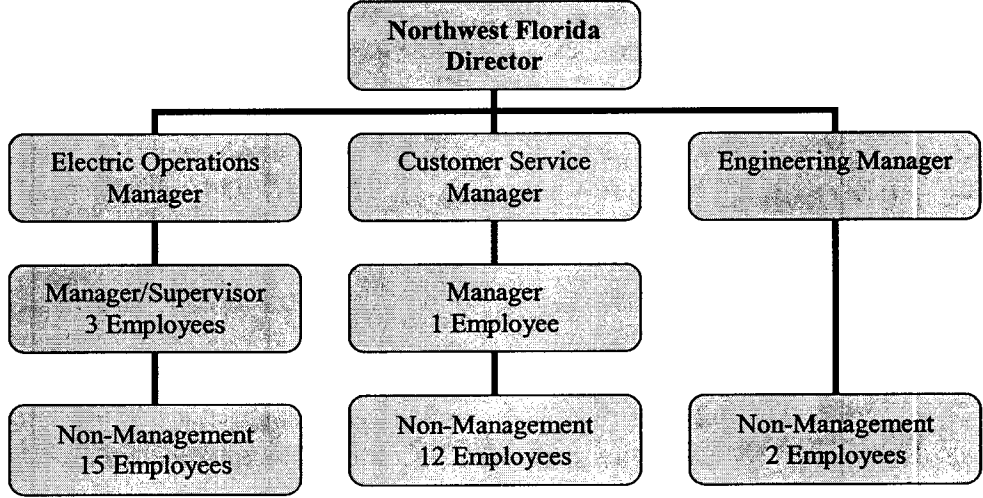


EXHIBIT 2

Source: Document Request 1.2

The Northeast division services approximately 14,566 customers with a service area of approximately 39 square miles, located on Amelia Island in Nassau county. The Northeast division purchases power from the Jacksonville Electric Authority. The company has approximately 23 miles of transmission lines and one transmission substation within the Northeast region. The Northeast division owns three distribution substations with 13 primary feeder lines covering approximately 41 miles in length.

3.1.3 Growth Characteristics

FPUC has experienced consistent growth during the review period from 1999-2004. Its customer base increased approximately 10 percent. **Exhibit 3** shows the average customer count annually for the company and its divisions during the period 1999-2004.

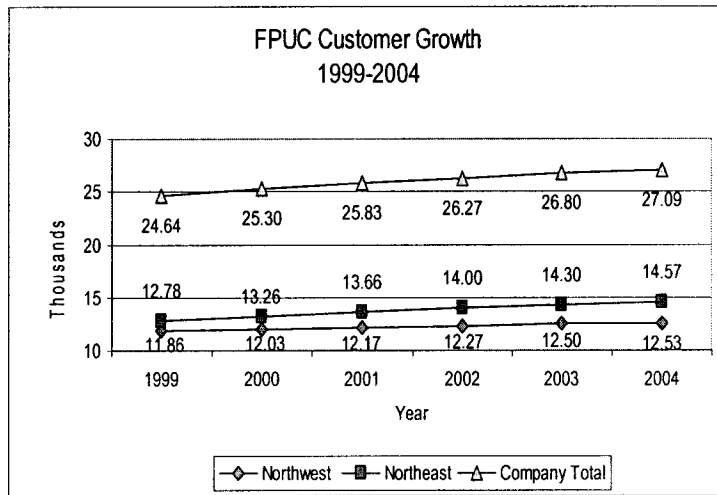


EXHIBIT 3 Source: FERC-1 Forms 1999-2003

The Northwest division has experienced a one percent average annual customer growth rate and a five-year increase of 5.6 percent. The Northeast division has experienced an average annual customer growth of 2.3 percent and a five-year increase of 14 percent. In recent years the population of Amelia Island has become less seasonal with more year-round residents.

According to company records for 1999-2004, revenues increased by approximately 14 percent over the period, from \$37,544,666 in 1999 to \$42,909,848 in 2004. **Exhibit 4** charts the revenue growth for the company during the review period.

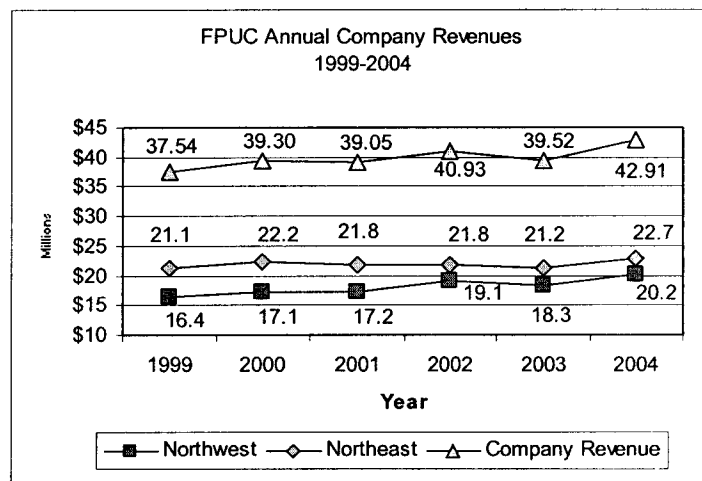


EXHIBIT 4 Source: FERC-1 Forms 1999-2003

As shown in the exhibit, the Northwest division has seen greater increases in revenue during the review period. The division experienced growth of 23 percent from 1999 through 2004. The Northeast division had smaller revenue growth during the period, with its largest increase occurring in 2004. Overall, division revenue increased 7.5 percent during the review period.

3.2 FPUC Statistical Measurements and Reports

Commission Rule Chapter 25-6, Part IV, General Service Provisions, Section 25-6.0455 requires each utility to file an annual Distribution Service Reliability Report. This report provides specific performance measurement indices representing the average system and customer outage frequency and duration during the calendar year. The Distribution Service Reliability Report also provides outage data for the utility's three percent of primary feeders with the highest number of feeder breaker interruptions during the calendar year.

FPUC captures and reports the required indices outlined in these rules, but is exempted from reporting MAIFIE (Momentary Average Interruption Event Frequency Index) and CEM15 (Customers Experiencing more than five Interruptions). Rule Chapter 25-6, Part IV, General Service Provisions, Section 25-6.0455 states that utilities providing electric service to fewer than 50,000 retail customers are not required to report MAIFIE and CEM15 indices. Presently, the company does not have methods to track these measures for trends and internal review.

3.2.1 FPUC Distribution Reliability Measures and Reports

Both of the divisions use a manual process for receiving, recording, and documenting outage information and calculating reliability indices. When an electric outage is reported to FPUC, a manual ticket is issued by customer service to the operations group. Field technicians are then dispatched to investigate and to correct the condition. Once complete, repair tickets are collected by the operations managers to record and file. The Northwest division compiles the outage information on an Excel spreadsheet, while the Northeast division compiles the data into an Access database. Each division uses this data to calculate the year-end reliability indices.

Each division calculates the reliability indices based on the outages in its area. A company total is compiled using the results from the raw data of both divisions. Company and division results are provided to the Commission annually. FPUC's two divisions vary in geography and design. The Northwest division is larger in miles serviced, with more aerial lines covering longer distances. The Northeast division is more urban and has fewer aerial lines, with approximately 50 percent of its system in underground facilities. The company states these differences can impact overall company outage totals.

Neither FPUC division has written guidelines or procedures on how reliability indices are processed and reviewed. Each Operations Manager has discretion in processing and recording outages and no formal guideline or policy exists requiring a timeline for recording or summarizing report data. Without documented procedures or guidelines in place, the collection and handling of outage information could differ between division and data could be compromised.

The company states its 2004 data does not include events caused by excludable conditions, as outlined in Chapter 25-6, Part IV, General Service Provisions, Section 25-6.0455(2). During 2004, exclusions were made for outages the company experienced during the hurricane season.

Reliability Performance - Duration Indices 1999-2004

The SAIDI, CAIDI, and L-Bar indices monitor the duration of outages. SAIDI (System Average Interruption Duration Index) is the average minutes of service interruption per customer served by the company. CAIDI (Customer Average Interruption Duration Index) is the average time it takes to restore service to interrupted customers. L-Bar is the simple average duration of all outage events.

SAIDI Results

Exhibit 5 shows that SAIDI results increased during the study period. The SAIDI numbers increased in 2001 and remained fairly constant in 2002 and 2003. In 2004, the SAIDI results increased 70 percent beyond the previous high of 2001. The company has not been able to reduce its system average minutes over the past four years to the levels it maintained during 1999-2000.

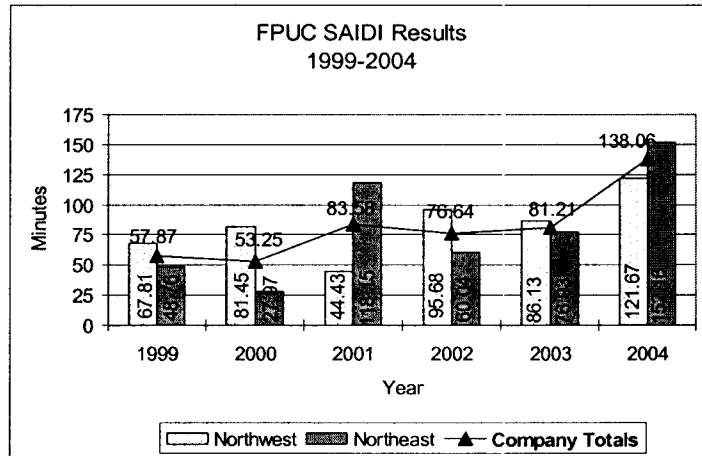


EXHIBIT 5 Source: Annual Service Reliability Reports Document Request 4.10

The exhibit also shows SAIDI results for each division. The Northwest division SAIDI results have fluctuated during the review period, with an overall increase in outage minutes. The division's three lowest SAIDI results were during the first half of the review period, with its three highest results occurring in 2002 through 2004. This trend shows the system average for outage minutes is on the increase in the Northwest division.

The Northeast division experienced its lowest SAIDI results during the review period in 1999-2000. The division has not been able to reduce its system average back to these levels in 2001 through 2004. The highest results occurred during 2004, with an increase of 98 percent from the previous year's results. Over the review period, the system average outage times have increased for the Northeast division.

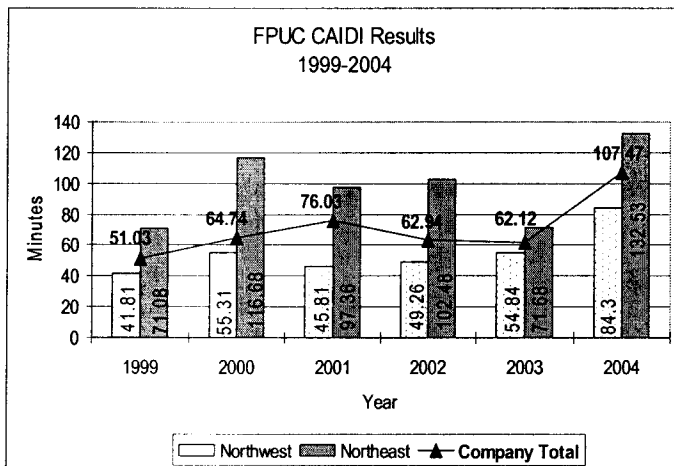


EXHIBIT 6 Source: Annual Service Reliability Reports Document Request 4.10

CAIDI Results

As shown in Exhibit 6 total company CAIDI results, the customer average interruption duration, increased each year from 1999 through 2001 and then declined in 2002 and 2003. However, in 2004, the CAIDI results peaked at 107.47 minutes. This is a 111 percent increase over the review period low of

51.03 minutes from 1999, or an average annual increase of 22.1 percent.

Overall, the Northwest division CAIDI results have also increased during the review period. The division experienced increased CAIDI results each year since 2001, with the highest jump in 2004. The Northwest division customers' outages lasted over 42 minutes longer in 2004 than in 1999, an increase of approximately 101 percent.

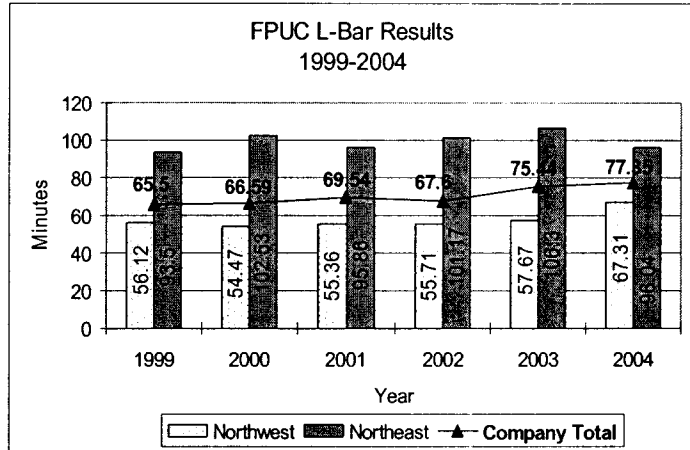


EXHIBIT 7 Source: Annual Service Reliability Reports Document Request 4.10

Northeast division customers experience longer average outages than customers in the Northwest division. This is attributed by FPUC to the higher percentage of underground facilities in the Northeast division. It tends to take longer to locate and repair damage in underground facilities, thus increasing the outage duration. The Northeast division experienced one peak in CAIDI in 2000, then attained some reduction during 2001-2003. However, in 2004, the Northeast division experienced its highest average interruption length at 132.53 minutes. This is an increase of 61.45 minutes from the review period low of 71.08 in 1999, an increase of 86.5 percent.

L-Bar Results

The company's L-Bar results, the simple average duration of interruptions, peaked in 2004 after several years of increasing results. The Northwest division maintained consistent L-Bar results during the review period with the exception of 2004. **Exhibit 7** tracks each divisions' L-Bar results for the review period. The Northwest division's 2004 results were the highest for the review period, increasing 17 percent from the previous year. The Northeast division's L-Bar results increased in 2002 and 2003 and then decreased in 2004. Overall, the division's lowest L-Bar results were in 1999.

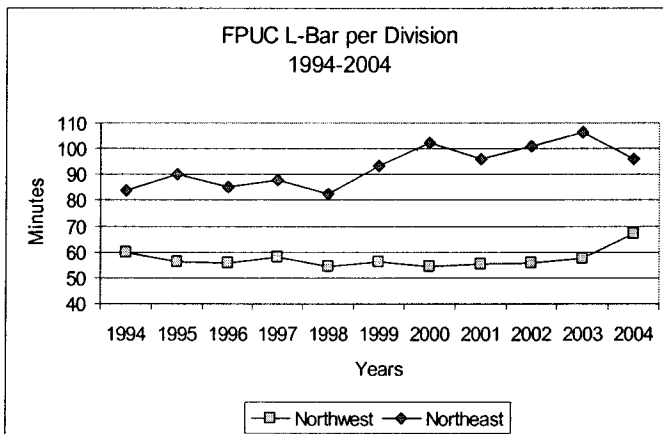


EXHIBIT 8 Source: Annual Service Reliability Reports Document Request 4.10

Staff also reviewed the company's previous Annual Service Reliability Reports to trend the 11-year L-Bar results for FPUC. **Exhibit 8** outlines the trend for both divisions. The Northwest division showed consistent L-Bar results, with a difference of only 5.3 minutes from its lowest to highest results during 1994-2003. The Northeast division showed an overall increasing trend in its L-Bar results over the past ten-year period. Although 2004 results were lower than in 2001 through 2003, they were 15 percent higher than the 1994 results.

Reliability Performance - Frequency Indices 1999-2004

The SAIFI and N indices monitor the frequency of outages. SAIFI (System Average Interruption Frequency Index) is the average number of service interruptions per customer served by the company. N is the number of outage events within the system. Together these indices give insight into how often outages affect the company’s customers.

SAIFI Results

Exhibit 9 shows the SAIFI results over the period 1999-2004. In 2000, the company had its lowest SAIFI results, .82 outages per customer. This rose to a high in 2003 with a result of 1.31 per customer. In 2004, the company lowered its SAIFI by two percent from the previous year.

Exhibit 9 also displays SAIFI results by division. While the overall company results have increased gradually, the divisions results have fluctuated, with each division at times adversely affecting the overall results. The Northwest division had the higher outage frequency of the two divisions in five of the six years reviewed. During the review period, the Northwest division posted its lowest SAIFI results in 2001 and then posted its highest in 2002. The Northwest division has since reduced its 2003 and 2004 results from the 2002 levels.

The Northeast division’s SAIFI indices have fluctuated during the review period. The division posted its lowest results in 2000, while posting its highest in 2001. The division’s 2004 results continue a three-year increase in SAIFI for the division.

Number of Outages

As Exhibit 10 shows, FPUC’s number of outages (N) decreased each year from 2001 through 2003 after two years of higher outages in 1999 and 2000. However, in 2004, the company posted its highest number of outages of the period with 938, this represents a 46 percent increase from the previous year. In 2004, the Northwest division experienced nearly a

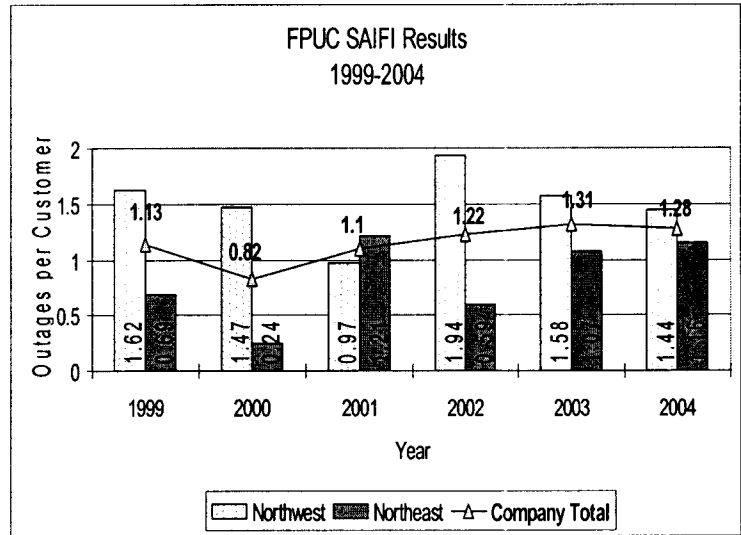


EXHIBIT 9 Source: Annual Service Reliability Reports Document Request 4.10

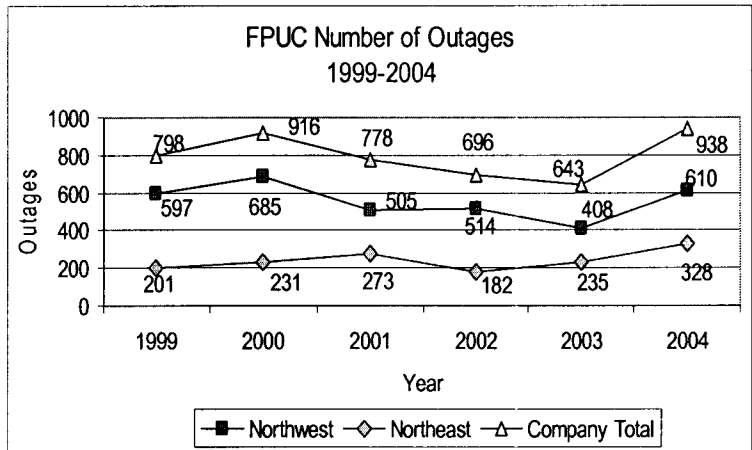


EXHIBIT 10 Source: Annual Service Reliability Reports Document Request 4.10

50 percent increase in outages from its six-year low of 2003. Prior to 2004, the division had reduced its number of outages each of the previous three years.

Overall, the Northeast division has fewer outages as compared to the Northwest division, possibly due to its lower exposure in terms of distribution line miles. The Northeast division had an upward trend in outages from 1999 through 2001, reduced the number of outages in 2002, and then increased the number of outages in 2003 and 2004. In 2004, the Northeast division's numbers grew by 39 percent over the previous year

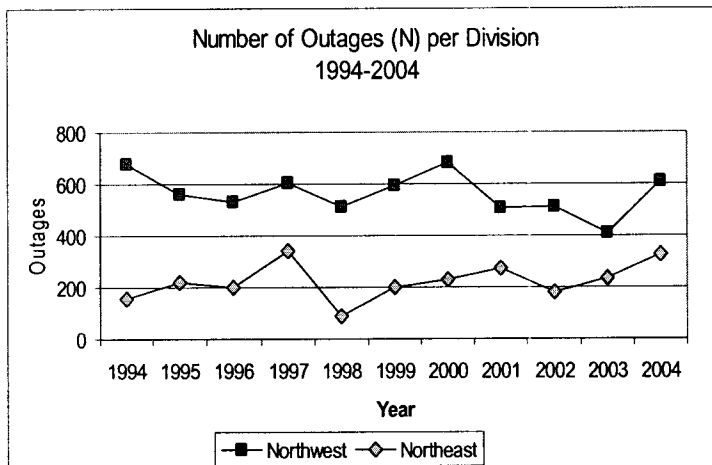


Exhibit 11 tracks the division results for the 11-year period 1994 through 2004. As the chart shows, the Northwest division increase in 2004 followed the three best annual results during the 11-year period. Both divisions have experienced periods of increases and decreases. The Northeast division's increase in 2004 follows two years of nearly average performance for the 11-year period, but overall trend is upward from the low in 1998.

EXHIBIT 11 Source: Annual Service Reliability Reports Document Request 4.10

Feeders with the Highest Outages

FPUC provides a listing of company distribution feeders with the three percent highest number of major outages to the FPSC annually in the annual Service Reliability Report. Due to FPUC's small number of feeders, the company is able to comply with the "three percent" requirement by reporting on a single feeder per division.

The Northeast division has 13 distribution feeders in service. The highest outages occurred on the Bailey Road feeder in 1999 and 2000, the Jasmine Street feeder in 2001, the Clinch Drive feeder in 2002, the Downtown feeder in 2003, and the 15th Street feeder in 2004. All of the feeders in the Northeast division territory are aerial lines and all are looped within the service grid. The division states it monitors events that occur on each feeder to determine what improvements can be made to prevent recurrence. The division reviews these occurrences on a case-by-case basis to identify corrective actions. The company states that while the Bailey Road feeder was on the list in 1999 and 2000, the feeder experienced fewer outages each year since 2000. In 2004, Northeast division management states no feeder experienced more than one major outage during the year.

The Northwest division has 16 feeder lines in service. The highest number of outages during the review period occurred on the College feeder in 2000 and 2002, the Hospital feeder in 2001, and the Bristol feeder in 2003 and 2004. The College feeder experienced three outages in 2000 and six outages in 2002. The Bristol feeder experienced three outages in 2003 and six outages in 2004. In comparison, the division feeder with the next highest number of outages experienced two outages in 2004.

Because of the construction design used in the Northwest division, 8 of the 16 feeders are of radial design, not looped with the service grid. Customers on these lines are more susceptible to longer duration outages because service cannot be routed to another feeder when a major outage occurs. This was the case when the Bristol feeder experienced a series of outages during July 2004. These outages resulted in the company proposing to implement new monitoring guidelines for this feeder.

In the July 2004 outages on the Bristol feeder, one outage was substation-related and the remaining five were caused by inadequate tree-trimming. The company stated in a July response to a Commission staff data request that a section scheduled to be trimmed “was skipped over in February [2004] due to wet conditions and in human error [we] forgot about it.”

Upon discovery of the trimming omission in July, FPUC immediately had the section trimmed. The outages associated with this incident caused the company to initiate new procedures requiring greater monitoring of this feeder line. Due to sections of this feeder being located over less accessible areas, the company has initiated quarterly walking inspections of this line.

The company states that it follows different procedures for vegetation trimming of the Bristol feeder. For this feeder, the Bristol service lineman, instead of the Line Department Supervisor, monitors and oversees the daily activities of the contract crew during the trimming. Since the Bristol feeder is located away from the larger service area near the Marianna office where the Line Department Supervisor is based, the company believes having the Bristol lineman monitor the crews is more efficient.

In response to a July 2004 Commission staff document request, FPUC outlined a series of steps the company is taking to correct certain problems with the Bristol feeder and to help alleviate future problems on the line. At that time, FPUC agreed to implement the following efforts:

- ◆ Improve access for tree-trimming and herbicide efforts by accessing secure gates from private landowners in the area,
- ◆ Install culverts in problematic areas,
- ◆ Complete quarterly walk-through inspections of identified problematic areas of the feeder,
- ◆ Install a new vacuum breaker/SEL 351A electronic relay on the system,
- ◆ Reduce feeder sag in the problem areas by installing additional poles along the feeder line, and
- ◆ Improve company radio communications capabilities in the area of the Bristol feeder.

Several of the above items were completed by the company in 2004, while others have been postponed until the second quarter of 2005. The company worked with private landowners in the area and installed interlocking locks on gates gaining access to culverts/crossings along the feeder line. With these locks, the company determined that it no longer needs to add culverts to access sections of the line.

The company also applied herbicide in August and October of 2004 to help prevent vegetation growth along the line. To document the newly required quarterly walk-through, the employee inspecting the area provides a signed inspection form to the Division Director each quarter. Staff was provided with a copy of the October 2004 inspection form signed by the Operations Manager. This new procedure will be outlined in the company's new line inspection procedures, which are discussed in Section 3.6.1.

The company states that it was not able to complete the installation of the vacuum breaker/SEL 351A electronic relays originally scheduled for October 2004. The new schedule for completion is April 2005 when the new SCADA (Supervisory Control and Data Acquisition) system is fully installed. Also, FPUC says it was not able to install the additional poles to the feeder line that were scheduled to be installed by October 2004. The engineering studies are in the final stages of review, and the anticipated installation date is in the second quarter of 2005. The company cites wet conditions, hurricane activities, and other obligations that prevented the projects from being finished as originally scheduled.

The company is still experiencing problems with poor radio coverage in the Bristol substation area. To improve radio communications, FPUC has used two different companies, with little success. The Northwest Division Manager is working with the current provider to improve coverage in this area. As of March 2005, the problem has not been corrected.

3.2.2 Additional Distribution Measurement Results

The

Northwest division is in the final stage of installing a new SCADA and mapping system. SCADA is a computer-based reporting system that is designed to capture specific outage and voltage data for analysis. Originally, FPUC anticipated the system to be installed by the fourth quarter of 2004, but due to delays, the company now expects that the system will be completed in the second quarter of 2005. The SCADA system will provide the Northwest division with the ability to automatically record outage information as it occurs. This information will be available to the division management for analysis and trending. Division management plans to use this information to expand its review and trending of outages. A SCADA system will not be installed in the Northeast division until 2009. Northeast division management will continue to manually collect outage data until that time. The current process is discussed further in Section 3.5.2.

3.2.3 Transmission Reliability Measurements

FPUC does not have a formal review process for tracking transmission outages. The Northeast division does biweekly monitoring of the voltage level on the transmission facility and reviews the electric load on the line. Division management documents and tracks these results on electronic spreadsheets for analysis and review. In the Northwest division, FPUC does not

monitor transmission reliability because all of the transmission facilities are operated by Gulf Power.

3.3 FPUC Design and Load Characteristics

3.3.1 Distribution Line and Substation Design and Loading

FPUC does not have written documentation covering design and loading procedures for distribution services and substation facilities. In response to a staff data request, the company states that it “utilize[s] standard electric utility practices” when designing load. The company states that, where necessary, it relies upon specification books and load design models from other electric companies for reference. FPUC has not made any changes to its design philosophy during the review period.

Distribution transformer loading is designed using a 70 percent load factor. On initial loading, the base is 75 percent of anticipated diversified load as provided by the customer. Feeder studies are conducted for growth areas as needed. These studies and projected load growth determine which projects are to be added to the division’s Five-Year Plans. The Five-Year Plans outline each division’s major goals and projects over the upcoming five year period. This effort seeks to ensure that service reliability and quality are maintained on a system level. If a customer issue occurs, localized upgrades are completed as the company becomes aware of them. The operations and engineering departments are charged with ensuring that all load designs meet the standard practice guidelines.

In the Northwest division, the number of residential customers served varies by residential neighborhoods. Transformer sizing is done on a case-by-case basis according to load. On average, FPUC serves two customers on a 25 KVA and four customers on a 50 KVA in residential areas. The 75 KVA is rarely used as other design constrains, such as voltage drop/flicker associated with secondary/service wire, limit its application.

The Northeast division averages one to four customers on a 25 KVA, four to six customers on a 50 KVA, and six to eight customers on a 75 KVA. In the Northeast division, 95 percent of all new construction is underground using pad-mounted transformers. Most commercial customers require three-phase power, which employs multiple transformers.

Since 2003, the Northeast division has been rebuilding and refurbishing the substation transformers within the three substations in the division. This has been a large capital improvement initiative for the company. This is being completed over several years and has been a major focus for the Northeast division management. The division’s goal is to have these improvements completed by March 2005, at a total cost of approximately three million dollars.

3.3.2 Transmission Line and Substation Design and Loading

FPUC does not have a large electric transmission system. The Northwest division does not have transmission facilities. The Northeast division has 23 miles of transmission lines and one transmission substation. The company has a double 138 KVA line connecting Amelia Island

with the Jacksonville Electric Authority substation on the mainland. This line was replaced and updated in 2001. The load capacity was increased to provide greater capacity load and now operates at approximately 75 percent of maximum load.

3.3.3 Monitoring and Measuring Voltage Levels

The company monitors its system load and voltage design by “going into the field and recording substation and line equipment data such as substation breaker relays, voltage regulators, and line reclosers.” This is done biweekly in the Northwest division and weekly in the Northeast division. The information is compiled in electronic spreadsheets for future analysis. The data is then used by the company for planning, analysis, and service quality evaluations.

When customers have a problem with load or voltage levels and FPUC is made aware of the problem, the company “utilizes voltage/amperage recording devices (digital memory/computer comparable) at the customer level” to monitor services. The company then evaluates the recorded data and takes corrective action to resolve the problem.

3.3.4 Constant Current Street Light Monitoring and Measurement

FPUC does not provide services that are covered under Chapter 25-6, Part IV, General Service Provisions, Section 25-6.047 for constant current street lights. FPUC does provide nonmetered lighting as a service to customers. This is a flat-fee product that is outlined in FPUC’s filed tariff with the Commission. FPUC does not provide public lighting in its territories.

3.4 FPUC Outage Causes and Coding

Chapter 25-6, Part IV, General Service Provisions, Section 25-6.044 of the FPSC Electric Rules requires each electric utility to keep a record of system reliability and continuity of service data, customer service interruption notices, and other outage data. The rule requires each utility to determine the cause of each outage and record it in a standardized manner throughout the utility. The rule also requires that each utility record the date and time of the outage event and the number of service interruptions for the event.

3.4.1 Distribution Outages and Coding

Examining the level and type of outages annually helps electric utilities identify and track outages across its serving area and within specific geographic areas of the company. Increasing levels of specific types of outages generally indicate declining levels of service and should become of concern to management. Once management identifies increasing levels and types of outages, it should redirect existing improvement programs or begin implementing new corrective programs.

As part of the Annual Reliability Report submitted to the Commission, FPUC reports the total number and primary causes of outages by type. **Exhibit 12** shows the number of outages by division for 1999-2004. For 2001-2003, the company reduced the number of outages each year. However, in 2004, the company had a 46 percent increase in outages over 2003.

FPUC Outage Causes 1999-2004													
Northwest Division							Northeast Division						
Cause	1999	2000	2001	2002	2003	2004	Cause	1999	2000	2001	2002	2003	2004
<i>Lightning</i>	187	197	151	164	80	133	<i>Lightning</i>	36	33	26	17	20	75
<i>Other weather</i>	39	54	37	28	31	49	<i>Other weather</i>	0	0	0	0	0	0
<i>Vegetation</i>	101	107	73	76	63	84	<i>Vegetation</i>	69	86	112	50	90	132
<i>Animal</i>	122	158	105	109	101	144	<i>Animal</i>	19	10	40	12	23	20
<i>Vehicle</i>	12	8	8	6	7	11	<i>Vehicle</i>	0	2	4	4	4	5
<i>Unknown</i>	80	107	83	85	70	106	<i>Unknown</i>	47	73	8	2	12	7
<i>Dig-In</i>	0	0	0	0	0	1	<i>Dig-In</i>	1	4	1	2	6	0
<i>XTMR failure</i>	39	22	15	18	27	17	<i>XTMR failure</i>	17	11	16	25	10	10
<i>Conductor failure</i>	8	0	0	0	0	0	<i>Conductor failure</i>	12	0	0	0	0	0
<i>Cut-out failure</i>	0	7	17	13	13	26	<i>Corrosion</i>	0	12	54	54	55	53
<i>Arrester failure</i>	0	0	5	0	0	2	<i>Salt Spray</i>	0	0	5	1	1	7
<i>Other</i>	9	25	11	15	16	37	<i>Other</i>	0	0	7	15	14	19
Annual Total	597	685	505	514	408	610	Annual Total	201	231	273	182	235	328
FPUC Total Outages 1999-2004													
1999	2000	2001	2002	2003	2004								
798	916	778	696	643	938								

EXHIBIT 12

Source: Document Request 1.13 & 4.10

In response to a staff document request, FPUC provided a copy of the definitions for each outage cause. BRR staff determined that although the company has definitions for outage causes, there is not consistency between the two divisions in categorizing outages based on the definitions. There are no written procedures to ensure the definitions are followed by each division or individual linemen. Exhibit 12 also shows the number of outages by cause for each division during the review period.

In the Northwest division, lightning, animal, vegetation, other weather, and unknown are the top causes of outages each year. In the Northeast division, vegetation is the most prevalent cause of outages, followed by corrosion, lightning, animals, and transformer failure. Company initiatives to address these causes are addressed in Section 3.6.1.

Unavoidably there will be some outages for which the lineman cannot identify the cause. These outages are categorized as unknown. In 2004, the Northeast division's unknown outages made up two percent of the total outages for the division, while in the Northwest division's unknown outages comprised 17 percent of all outages in the division.

Staff has identified some inconsistencies on how the two divisions categorize outages. Staff noted the other weather category is used by the Northwest division based on the definition which states, "Service interrupted by weather conditions not covered by exclusions; usually high winds/heavy rains associated with thunderstorms or cold fronts. Usually trees blown over or tree limbs separated from tree from outside the 10 foot clear zone, contacting distribution lines." However, the Northeast division management categorizes the same type outages into the vegetation outages category. This difference in categorizing causes the annual Service

Reliability Reports to include inconsistent and, therefore, inaccurate counts of other weather and vegetation.

Such inconsistency means accurate analysis cannot be performed on the causes of outages. This difference in categorizing outages could prevent the company from correctly allocating resources based on the true root cause of the outage. A uniform classification of outage codes, reported similarly by both divisions, would ensure that all like outages are correctly reported to the Commission on a going forward basis. While it is FPUC's choice to categorize outages in a manner that is best for its electric operations, consistency between the divisions is essential in providing accurate data to the Commission.

3.4.2 Transmission Outages and Coding

FPUC's Northeast division management does not track outages on its transmission facilities. However, the division does monitor transmission line voltage and perform periodic maintenance on the facilities. The Northeast division does not have written guidelines or procedures for monitoring and recording transmission outages. The company states that with only one transmission line in the Northeast division, any outage on the facility would impact the entire service area. Management would immediately be aware of any of these type events.

The Northwest division purchases power from Gulf Power at the substation level. Therefore, any problems associated with Gulf Power's transmission of electricity are not reported in FPUC's data. When an outage occurs on Gulf Power's substations, FPUC usually arrives at the location first to investigate. Gulf Power allows FPUC to perform switching in an attempt to restore service to the customers and reduce outage duration. FPUC states that it works closely with Gulf Power to coordinate scheduled interruptions and perform necessary switching on the system to minimize the impact on its customers.

3.5 FPUC Trouble Reporting and Repair

3.5.1 Trouble Reporting

During normal business hours, trouble reports are handled through each division's office. When a customer outage is reported, the information is collected by the FPUC customer service representatives. The representative collects outage information from the customer and notes the time the outage is reported. The representative then dispatches a lineman for repair. FPUC does not have written procedures for its trouble reporting process or for completing repair reports.

During non business hours, each division outsources the handling of its calls to an answering service. Each division has an agreement with a local provider in its area. The representative collects the outage information and contacts the on-call company linemen or supervisor for dispatch. When the work has been completed, the company lineman notifies the answering service dispatcher that the problem has been corrected. The answering service provides all outage details to the FPUC operations manager the following business day.

3.5.2 Trouble Repair

The trouble repair process begins when an FPUC lineman is dispatched to locate and correct the trouble. Once the problem is corrected, the lineman records the restoration time and

the number of customers impacted by the outage is calculated. This information is passed back to the dispatching representative for recording. At present, neither division has an automated system to calculate the number of customers affected by an outage. The lineman must estimate the number of customers affected by an outage based on the distribution configuration and the particular cause involved. The company does not keep records of the number of repair and restoration dispatches and, because of its manual collection process, the company was not able to provide the number of repair and restoration troubles completed during the review period.

As of the first quarter of 2005, the Northwest division is in the final stages of completing the installation of a SCADA system within the substations. It will eliminate many of the manual reporting procedures used in the Northwest division. The SCADA system will report problems and outages located at substations and has the future ability to report at the feeder level. Along with the installation of the SCADA system, the Northwest division is adding a computerized mapping system that will chart the system to the customer level. This system will allow the divisions to more accurately calculate the number of customers affected by outages.

In a February 24, 2004 letter to Commission staff, FPUC noted that “the Northeast Florida Division will be updating their substations and adding a SCADA system within the next five years.” The Northeast division has been in the process of updating substation equipment and plans to install the SCADA system in 2009. A new mapping system is also planned for the Northeast division, but the company’s target date was not available. The Northeast division will continue the current manual process of recording and documenting outages until the system is online.

3.6 FPUC Reliability Improvement Programs

Each division determines its yearly operations and maintenance budget based on anticipated projects and maintenance needs. Differences in service territories and facilities require programs to be tailored to fit the specific needs of the two divisions. While periodic meetings are held between division management personnel, individualized division goals and budgets are maintained. The divisions propose budgets in the third quarter of each year, and corporate management approves the final budget for the upcoming year during the fourth quarter.

Annually each division creates a Five-Year Plan that outlines and forecasts its major projects for the upcoming five-year period. The Five-Year Plans for the Northwest division were provided for each year 1999 through 2004. The Northeast division provided a copy of the 2004 Five-Year Plan, but states the division did not prepare a Five-Year plan prior to 2004. The division did provide a listing of projects completed in the division for each year of the review, but staff was not able to determine what projects were initially outlined for implementation.

The two divisions’ 2004 Five-Year plans outline the company’s major goals and initiatives for the upcoming period. Examples of upcoming work noted in the plans include the Northwest division making modifications to several of its feeders and the Northeast division is performing maintenance work on its 69 KVA transmission lines and its Amelia Island Plantation substation.

3.6.1 Distribution Reliability Improvement Programs

Each division manager and his staff evaluate the needs of the division and distribute the overall budget accordingly. The company does not allot budget dollars to specific maintenance programs or initiatives. According to the company, actual and budgeted costs for each operation and maintenance program are not separately tracked in the FPUC accounting system. FPUC has ongoing programs in areas such as vegetation management, lightning arrester installation and maintenance, substation maintenance (Northeast only), line recloser maintenance, and inspections (meter, pole and line, feeders, underground, maintain capacitor banks, and substation). These programs are discussed in greater detail within this section.

Exhibit 13 shows the overall operation and maintenance budget and actual dollars spent by FPUC. This is the total electric expenditures for both divisions over the period 1999 through 2004. The overall budget increased each year from 1999 through 2004. The company outspent its budget each year except 2004.

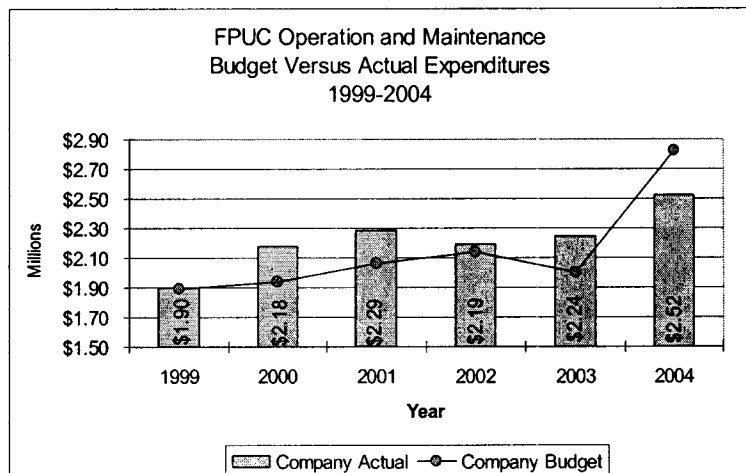


EXHIBIT 13

Source: Document Request 1.19 & 4.10

Exhibit 14 shows each division's expenditures for operations and maintenance during 1999 through 2004. Over this time, Northwest division expenditures increased in 2000, declined in 2001, and has been on an increasing trend from 2002 through 2004. The Northeast division expenditures increased in 2000 and 2001, dropped slightly in 2002 and 2003, and increased in 2004. Expenditures were below the 2000 level during 2002 and 2003 for the Northeast division.

FPUC does not set specific reliability improvement objectives or measurements for distribution programs and initiatives. The overall goal of the company is to reduce the number of interruptions and improve the service reliability indices. The company states that it has not seen an impact in the number of service interruptions or indices based on the results of Operations and Maintenance reliability improvements programs and initiatives conducted within each division during the review process.

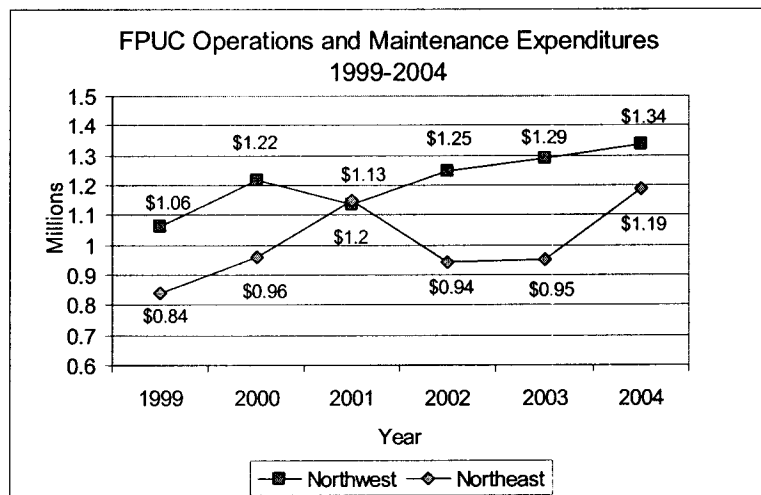


EXHIBIT 14

Source: Document Request 1.19 & 4.10

The company states that many of its current initiatives discussed below are still in the early stages of implementation, and, therefore, the improvements have not had time to cycle through to produce results. According to the company, budget constraints have not allowed greater focus on many of the initiatives. The exception is the increased Northwest division vegetation management funding granted in the 2004 FPSC rate case.

Without reliability improvement goals and objectives set by FPUC, it is difficult for the company to monitor and verify a project's effectiveness at improving the company's service reliability. The company does not allocate specific dollar amounts for these programs and initiatives, preventing management from analyzing the effectiveness of the program in relation to the dollars spent.

Overhead inspections

FPUC conducts overhead line and pole inspections within each division. The Northwest division is on a ten-year cycle for completing the inspection of overhead lines, while the Northeast division inspects each line and pole annually. According to FPUC, different timelines are necessary because of the larger service area in the Northwest division as compared to the Northeast division. The Northwest division has 20,816 poles in service compared to 4,427 in the Northeast division.

The inspections are usually conducted during spring and early winter when workloads are lighter. The company states that the inspections include monitoring the pole quality, arresters, and the overall condition of the facilities. The linemen will repair minor problems while the inspections are being conducted and report any larger problem to the operations management for future repair. Management creates a work order to correct the problems found during the inspection. FPUC does not currently have a uniform inspection form for the linemen to use to document inspection results. The company states that a new inspection form is being developed and will be in place March 2005.

Presently, the Northwest division documents inspections on a form that records pole conditions, line condition, pole location, vintage of pole, and other maintenance information. BRR staff was provided with inspection reports from 2000 (when these forms were implemented within the division) through 2003. The company did not complete any overhead inspections during 2004. The company states that, because of the Northwest division's focus on implementing the SCADA system, the inspection cycle has been delayed by one year, effectively making the current inspections process an 11-year cycle.

The Northeast division inspects overhead facilities on an annual basis. The Northeast division management states that the inspection process includes the same monitoring and review as in the Northwest division. Like the Northwest division, the Northeast division reported it had not completed any overhead inspections during 2004. The company states time constraints caused by the division's focus on the refurbishing of substation equipment prevented the inspections from occurring. Management plans to resume the inspections in 2005.

The Northeast division was not able to provide documentation showing that the overhead inspections were completed during 1999-2003. There has been management turnover and transition in the division, and the documents related to inspections were either misplaced or destroyed. Without this documentation, BRR staff was unable to verify whether any overhead inspections have been completed in the Northeast division during the review period 1999-2004.

During the review period, the company did not have written procedures outlining the goals, objectives, and requirements for conducting overhead inspections. With the inconsistent record retention between the two divisions, the lack of 2004 inspections, and no written procedures, BRR staff was not able to confirm that the two divisions conduct inspections in the same manner or review the same criteria during the inspections.

The company states that the divisions Operations Managers are currently developing written procedures for line inspections. According to the company, this document will outline requirements for linemen to follow when conducting these inspections along with a uniform inspection form for linemen to document their findings. This document will also include the inspections process for the Bristol feeder previously discussed in Section 3.2.1. The company anticipates implementation of these procedures in March 2005.

Underground Inspections

Underground facilities inspection is conducted yearly by both divisions. Because of the growing number of underground facilities in the Northwest division, management is contemplating expanding the inspections to a biannual timeframe. According to the company, linemen completing inspections monitor each underground pad for damage, rodent infestation, insect problems, and damage to insulation and ensure all security locks are working. These inspections are usually conducted during the summer months. As with the overhead inspection process, the company did not have written procedures for completing underground inspections during the review period. Due to the lack of inspection documentation and procedures, BRR staff was not able to confirm underground inspections are conducted in a uniform manner within and between the divisions.

The Northwest division documents underground inspection results on a form that records the condition of the unit as found, the condition of the mechanics and equipment, the condition of the pad, and any vegetation/pest infestations. If there is a minor correctable condition, the lineman repairs the problem while inspecting the unit. If the problem requires a follow-up visit, the lineman issues a work order through electric operations for the repair.

The Northwest division provided BRR staff with the underground inspection reports for 1999-2002. Division management stated that, in 2003, approximately 60 percent of the required inspections were completed, but the company could not locate any of the completed forms to provide to staff. As with the overhead inspections, the Northwest division did not complete any underground inspections in 2004. The company plans to resume the inspections in 2005.

The Northeast division management states underground inspections are done in the same manner as the Northwest division, but were also unable to provide copies of the results of the underground inspections for 1999-2003. These documents were misplaced or destroyed as were

the overhead inspection results. The division did provide a copy of the "Pad Mount Security Checklist" for March 13, 2003 through March 28, 2003. These reports reflect the visual inspections of the secured padlocks. BRR staff was not able to confirm that any underground inspections were completed by the Northeast division during the review period. As with the overhead inspections, the Northeast division has not conducted underground inspections during 2004. The company plans to resume the process in 2005.

The new linemen inspection procedures being developed will include procedures for inspecting underground facilities. A new underground inspection form will also be included as part of the new procedures. Once implemented, these procedures should provide the divisions with uniform procedures on conducting and documenting line inspections.

Engineering Inspections

In the Northwest division, feeder engineering inspections are completed on a six-year cycle. The company reviews the engineering structure and loads of feeders and evaluates future needs. In response to a staff document request, the company was not able to provide copies of the division's seven engineering inspections completed during 1999-2001. The company states it could not locate these studies. The company provided copies of two of the three studies completed in 2002 and the three studies completed during 2003 and 2004. The company stated that one of the two feeder inspections scheduled for 2004 was postponed until the first quarter of 2005.

The Northwest division feeder studies analyze feeder voltage levels, overload studies, capacitor studies, phase loading, and system coordination on the feeder. Each study includes recommendations of potential improvements to the feeders. Recommendations are reviewed by division management and engineers to determine the feasibility of implementation for each. Those recommendations accepted to be implemented are added to the division's Five-Year Plan. The division anticipates that the upcoming additions of the mapping and SCADA system in 2005 assist in and improve the completion of annual engineering studies.

The Northeast division has not formalized its feeder study program. Instead, the division combines the engineering study and the annual overhead inspections. The Northeast division completes weekly substation feeder readings and, based on those weekly reports, the company moves circuits to balance loads and installs any necessary equipment to improve the system. However, there is no formal documentation of the actual studies.

The Northeast division did provide a copy of the *Substation Loading Assessment and Improvement Recommendation* issued in October 1999 by its engineering department, which shows the ten-year loading forecast for the Northeast division's substations and feeders. The report was an eight-month study that assessed both current and future conditions and outlined improvements for the system through 2008. The substation improvements that the Northeast division has been implementing since 2003 are outlined in Section 3.3.1.

As with the overhead and underground inspections, the company does not have written procedures for formal or informal engineering inspections. Without written procedures and

guidelines, there is not consistency between the two divisions on how the studies/inspections should be completed or how often they should occur.

Pole Replacement

During the overhead inspection process, the company evaluates the condition of the poles in service. Linemen inspect the poles and determine which poles should be replaced or repaired. **Exhibit 15** shows the number of poles replaced annually from 1999-2004. The Northwest division replaced 1,384 distribution poles during period 1999-2004, for an average replacement of 230 poles each year. At year-end 2004, the Northwest division had 20,816 distribution poles in service.

FPUC Poles Replaced per Division 1999-2004				
Year	Northwest Distribution	Northeast		
		<i>Total</i>	<i>Distribution</i>	<i>Transmission</i>
1999	113	36	34	2
2000	247	39	36	3
2001	256	76	9	67
2002	267	37	36	1
2003	238	33	30	3
2004	263	37	36	1
Total	1,384	258	181	77

EXHIBIT 15

Source: Document Request 3.2, 4.5, 4.10

The Northeast division replaced 181 distribution poles during the 1999-2004 period, for an average replacement of 30 poles annually. The Northeast replaced 77 transmission poles during the review period. The majority was during the main transmission line upgrade in 2001. At year-end 2004, the Northeast division had 4,427 distribution and 303 transmission poles in service.

The company was not able to provide the average age of poles in service or the number of poles in service annually for the entire review period. The company states that the corporate computer database was not set up to maintain the information for this period. The company did provide the information for 2003 and 2004 as shown in **Exhibit 16** and **Exhibit 17**. FPUC increased the number of poles in service from 2003 to 2004 by 337 in the Northwest division and by 46 in the Northeast division.

FPUC Northwest Division Distribution Poles in Service 2003-2004				
	2003		2004	
<i>Distribution Pole Type</i>	Average Age Poles in Service	No. Poles in Service	Average Age Poles in Service	No. Poles in Service
30'	21.4	6,105	21.7	6,205
35'	31.7	7,577	32.6	7,470
40'	15.6	4,526	15.6	4,730
45'	19.4	1,690	18.8	1,798
50'	18.4	386	17.5	415
55'	25.7	123	26.	126
<i>Other Poles</i>	32.2	72	31.9	72

EXHIBIT 16

Source: Document Request 4.5

FPUC Northeast Division Distribution Poles in Service 2003-2004				
	2003		2004	
<i>Distribution Pole Type</i>	Average Age Poles in Service	No. Poles in Service	Average Age Poles in Service	No. Poles in Service
30'	21.8	874	22.6	884
35'	37.6	1,741	38.6	1,743
40'	17.4	1,324	18.1	1,337
45'	14.3	380	14.6	395
50'	19.3	30	17.4	35
55'	6.5	2	5.2	3
<i>Other Poles</i>	24.5	30	25.5	30

EXHIBIT 17

Source: Document Request 4.5

FPUC management states it maintains a three-month inventory of poles. The number of poles on hand is based on a three-year running average of pole use. The company adjusts inventory levels as needed for anticipated projects. The company receives pole shipments quarterly to maintain the reserve level. In May of each year, the company increases the reserve to a six-month inventory level to prepare for potential hurricane recovery efforts. The company reports that it did not have any issues with maintaining its pole inventory levels during the 2004 hurricane season despite the obvious increased demand caused by storm damage across the state.

The company does not have written procedures outlining the inventory of equipment reserves. Each division's Operations Manager and his staff are responsible for monitoring and ordering equipment and maintaining adequate supply. The two divisions maintain separate inventories and order equipment independently of the other. However, division management

acknowledges that certain purchasing power benefits could be realized by standardization and consolidation of division material purchasing.

Lightning Protection

Lightning is one of the largest causes of outages for FPUC. Lightning has been the leading cause of outages in the Northwest division for five of the past six years. **Exhibit 18** and **Exhibit 19** show both the number of lightning-related outages and the number of arresters replaced by each division during the review period.

Exhibit 18 shows that, in 1999 and 2000, the Northwest division had a higher number of lightning-related outages during the review period, while it replaced fewer arresters during these years. FPUC increased the number of arresters replaced by the Northwest division in 2001-2003, with a peak in 2003. The division reduced the number of arresters replaced in 2004 back to the 2002 level. In general, an increase in arrester replacement appears to have caused a decrease in lightning outages.

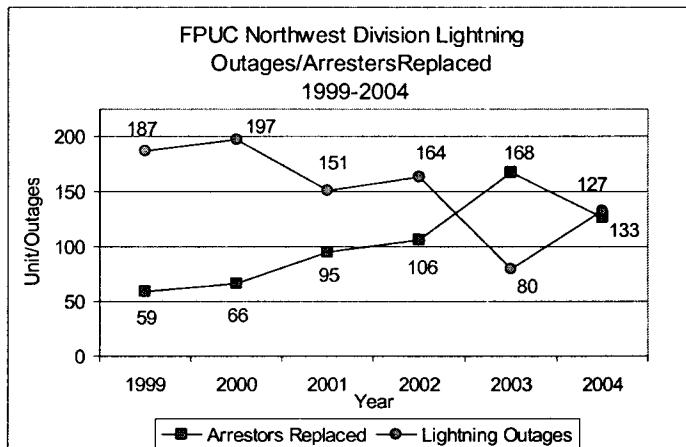


EXHIBIT 18 Document Request 1.13, 3.8 & 4.10

In the Northeast division, the geographic area is smaller and a higher percentage of the system is underground; thus having less exposure to lightning events. Lightning outages are still in the top five causes of outages for the division. Exhibit 19 shows that in 2004, the Northeast division’s lightning-related outages more than doubled from the previous high in 1999. The company has not conducted any analysis of weather patterns for 2004 to determine if there were an abnormally high number of lightning strikes in the region during the year or if the increase was system related.

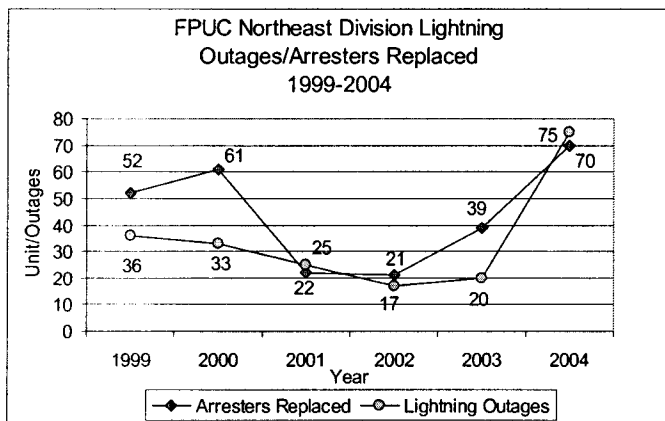


EXHIBIT 19 Document Request 1.13, 3.8 & 4.10

During 2001-2003, the division reduced the number of arresters replaced each year. While the company did increase the number of arresters replaced in 2004, 48 of the replaced arresters were part of a maintenance upgrade on a specific section of line. This work was not in response to the increased lightning during the year. These replacements may reduce future outages.

Corrosion Protection

Corrosion outages have been a concern for the Northeast division during the review period. The division, servicing a barrier island on the Atlantic coast, experiences corrosion caused by the effects of the ocean environment. Corrosion-related outages have increased each year since 2000, the year the company started reporting these outages as a separate category. Corrosion is the second leading cause of outages in the Northeast division behind vegetation-caused events. Corrosion-related outages are not an issue within the Northwest division since its territory is less susceptible to corrosion-damaging elements.

The Northeast division has an initiative to replace transformers and switching devices with stainless steel models. The company could not provide the percentage of the system which has been replaced to date and states it will take many years to complete the project. At present, all new transformers and switching devices installed are stainless steel models. Any faulty existing transformers will be replaced with the new stainless steel equipment. No specific portion of the maintenance budget is earmarked for this initiative. Over the long term, the company expects to see a reduction in outages caused by corrosion.

Animal Protection

The Northwest division has a high number of outages attributed to animals. The division has an ongoing initiative to upgrade animal protection devices on feeders and laterals where needed. The goal of this project is to reduce the number of animal-caused outages that occur each year, although no specific minutes of interruption or number of outages are targeted. The company monitors animal-caused outages to determine which areas are being most impacted.

The Northwest division has a particular problem with squirrels. When the Northwest division identifies a problem area, updated preventative devices are installed to help alleviate animal-caused outages. The division is updating its devices with units that create static electricity as way to ward off the animals. While these installations are ongoing, the division does not have a timeline on when the replacements will be complete, nor how much of the territory will be retrofitted with the new devices each year. The division does not budget a specific dollar amount for this initiative, and the company states overall budget considerations constrain the initiative.

The Northeast division does not experience as many animal-related outages. The division, being more urban, does not have as many problems with animals damaging the equipment. The division does use animal deterrent devices where needed, but has not encountered the same problems as the Northwest division.

3.6.2 Transmission Reliability Improvement Programs

The Northeast division has a program to monitor and evaluate its transmission facilities. According to FPUC, the small, compact size of the division does not require the programs to be large and extensive. The Northeast division conducts vegetation management, substation maintenance, and transmission pole and line inspections for the transmission facilities.

Division management states that the transmission line inspections consist of a visual inspection of the overall facility during normal maintenance and daily activities. The division does not have written guidelines or procedures outlining this process. The transmission facility has recently been updated, and concrete poles have been added to portions of the main line. The company completes monthly inspections of substation facilities.

3.7 FPUC Vegetation Management Program

Each division has a separate annual budget allocated for vegetation management through the division's operations and maintenance budget. **Exhibit 20** tracks the annual vegetation expenses for each division along with the overall company total. The Northeast division's figures (and company total) include both distribution and transmission budget dollars. Any allocated dollars from the company's hurricane fund are not reflected in these totals.

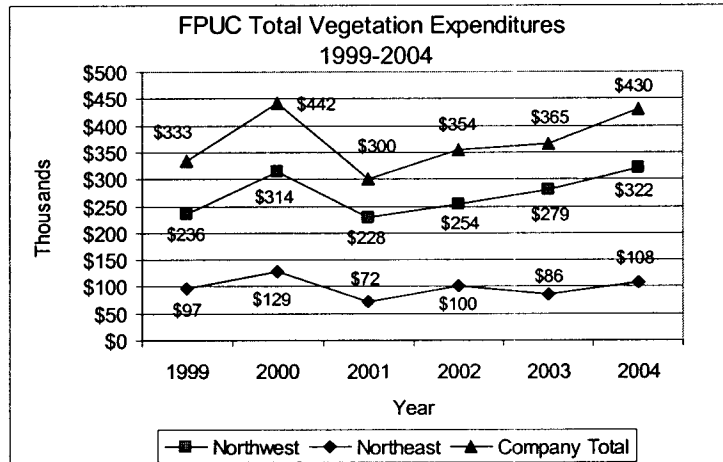


EXHIBIT 20 Source: Document Request 2.7 & 4.10

3.7.1 Distribution Vegetation Management

Northwest Division

The Northwest division, being a rural territory, has a large number of trees in its service area. The division operated until 2004 with two full-time tree-trimming crews and one part-time crew. One crew consists of two contractor employees. After the 2004 FPUC rate case, FPUC increased its tree-trimming force to four crews in the Northwest division. **Exhibit 21** shows the Northwest division's annual budget and actual dollars spent for vegetation management. As shown, the budget has remained the same for each year from 1999 through 2003 at \$275,000 and was increased in 2004 to \$322,000.

During the review period, the Northwest division did not maintain a consistent tree-trimming cycle. In 1999-2001, the Northwest division did not trim specific feeders and laterals, but conducted hot-spot trimming within its service area. Hot-spot trimming

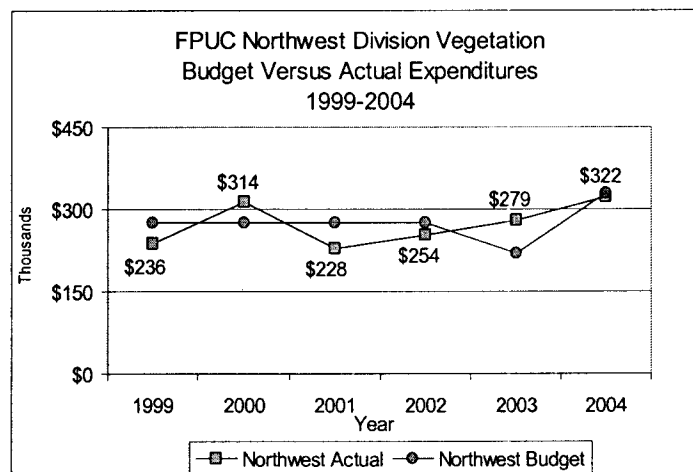


EXHIBIT 21 Source: Document Request 2.7 & 4.10

involves monitoring and trimming sections of vegetation that are in direct contact with, or encroaching on, a line or equipment. Hot-spot trimming can occur in response to a vegetation outage, customer calls, or company personnel identifying an area where vegetation is encroaching on the lines.

In 2002, the Northwest division initiated cycle trimming on its feeder lines. During this time, the division was using the services of two tree-trimming companies. Based upon the performance observed, the division signed a new three-year contract in 2003 with one of these companies and continued with the cycle trim schedule. In 2004, as a result of inadequate trimming during the 2002 schedule, the division had to hot-spot trim sections of two recently-trimmed feeders. The company states that, in 2002, budget constraints prevented the company from having contractors clear the vegetations to the specified ten-foot clearance. In addition, the crew of one contractor did not perform to the company's expectations. The company states that an increase in trimming crews and FPUC's greater oversight on the productivity of the trim crews should alleviate this problem in the future.

In 2004, three of the four feeders scheduled for trimming were completed, with the remaining two scheduled for completion by the end of the first quarter of 2005. The Northwest division's five-year trim cycle started in 2002 with a 2006 completion planned. Along with cycle trimming, the division still uses hot-spot trimming when needed. The Northwest division has approximately 900 miles of aerial lines in service, and the company states that, with the expanded crews, it should trim approximately 45 miles of lines per crew annually. At present staffing and productivity levels, the Northwest division would complete 180 miles of cycle trimming annually. This could be reduced when crews complete hot-spot trimming. BRR staff believes that the division should be able to effectively complete its five-year trim cycle with current staffing and productivity levels.

The Northwest division monitors the tree-trimming process by highlighting completed sections on feeder maps. As sections are trimmed by the contractors, the Line Supervisor marks off the section of the map. FPUC provided BRR staff with the completed trim maps and the corresponding productivity logs for each feeder trimmed from 2002 through 2004.

The manner in which FPUC tracks its vegetation procedures does not ensure all required trimming is completed by the tree crews. As mentioned in Section 3.2.1, a portion of the Bristol feeder was skipped in 2004 during its vegetation trim cycle, and the company neglected to return and complete the work. During this time, the company was using the method of highlighting its maps to note which areas had been completed. If this process of documenting the trim results was effective, this oversight would have not occurred.

Northeast Division

In 2004, the Northeast division started a two-year trim cycle for its feeders and laterals and uses hot-spot trimming as needed. In previous years, the division conducted yearly hot-spot trimming. The division starts at the north end of the island and continues tree trim activities towards the south end of the island. The division keeps track of the progress on a color-coordinated map. BRR staff was provided a copy of the 2004 trim map showing the completed work for the year.

When questioned about efforts to reduce vegetation outages in the division, Northeast division management responded that, in 2004, it is focusing more resources and emphasis on the tree-trimming maintenance program.

The division has changed its vegetation management from yearly hot-spot trimming to a two-year trim cycle. While the company states it is placing greater emphasis on tree-trimming in 2004, the budget for that year was still below the 1999 through 2002 amounts.

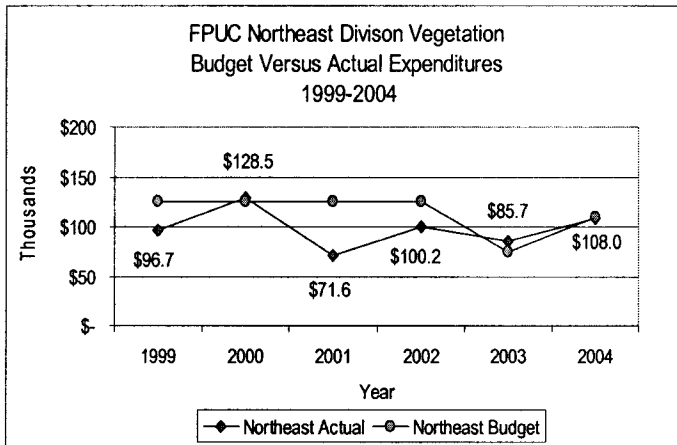


EXHIBIT 22 Source: Document Request 1.7 & 4.10

During three of the six years, the division spent less on vegetation management than originally budgeted by the company. When asked about these three years, the company states that sometimes productivity is lost due to absenteeism because it utilizes just one tree crew in the division. Also, the company stated that it did not meet its budget amounts at times because the tree crews conducted more right-of-way clearing, which is less costly than tree removal.

Exhibit 22 shows the Northeast division’s vegetation budget and actual dollars spent during the review period.

During three of the six years, the division spent less on vegetation management than

The company is in the process of creating a written vegetation management procedure. A draft copy of the procedure was provided to BRR staff in December 2004. According to the draft procedure, the Line Department Supervisor will be responsible for the daily oversight of the tree-trimming contractor. The Line Department Supervisor, after a visual inspection of the lines, will note on a map the areas that are to be trimmed. This map will be provided to the trimming crews for reference. The Line Department Supervisor is charged with monitoring the crew and verifying contractor’s weekly productivity and time sheets. The Line Department Supervisor inputs the contractor’s information into the division’s Vegetation Management Productivity Log. The Operations Manager is responsible for the supervision of the Line Department Supervisor. The company plans to implement this procedure in March 2005.

3.7.2 Transmission Vegetation Management

FPUC’s Northeast division completes both transmission and distribution trimming activities within the same two-year distribution trim cycle. Sections of the line are scheduled for trimming each year along with the distribution feeder system. The transmission trimming cycle is tracked on a color-coded map similar to the one used for distribution trimming. The division provided BRR staff with a copy of the map showing the 2004 completed sections. The map showed the division was on year one of the two-year cycle. Hot-spot trimming also occurs when necessary on transmission lines similar to distribution system. The Northwest is not responsible for any transmission vegetation management because the company does not own any lines in the area.

3.8 FPUC Damage Claims Processing and Reporting

In certain situations, FPUC pays claims for damages caused to customers' personal property. These claims are handled within each division for resolution. The company does not provide information regarding claim procedures to its customers. When a claim is filed by a customer, an FPUC supervisor investigates the allegations

and determines whether the claim warrants payment. Once directed to the manager, the claims are reviewed for merit. FPUC only pays claims when it determines that a company error caused the damage, and it does not retain records on claims denied by the company. If there is a dispute, the claim is escalated to division management. **Exhibit 23** outlines the number of claims paid annually and **Exhibit 24** shows the total dollars paid by FPUC during the review period.

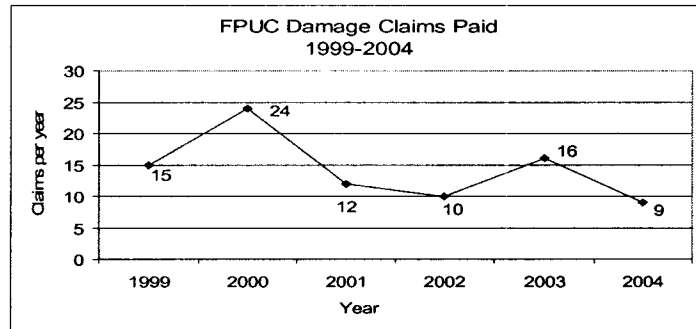


EXHIBIT 23 Source: Document Request 3.6 & 4.10

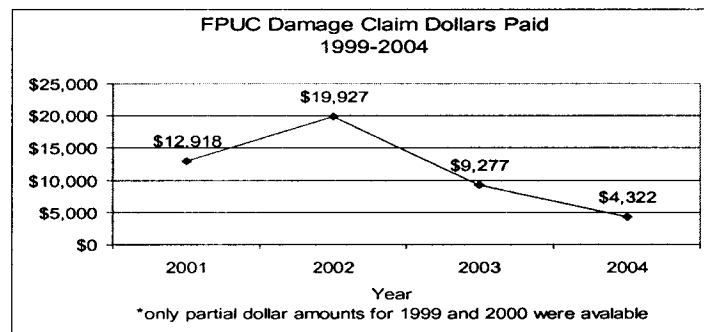


EXHIBIT 24 Source: Document Request 3.6 & 4.10

The company does not have a written procedure on claims processing. The investigating supervisor makes the determination on whether a claim warrants payment. There is not a written policy in place to ensure consistency in handling damage complaints throughout the company.

3.9 FPUC Customer Complaint Reporting

Along with the reliability indices reported to the Commission, customer inquiries and complaints provide insight into the quality of service for a company. The numbers of both FPUC-received and FPSC-received customer complaints are relatively low. For the period 2000-2004, FPUC logged 47 internal complaints, averaging nine per year. FPUC could not provide internal complaint records for 1999.

In the same 1999-2004 period, the Commission logged 49 electric complaints involving FPUC. In the 2003 *Review of Florida's Investor-Owned Electric Utilities' Distribution Reliability*, Commission staff states that, of the 40 complaints logged with the Commission 1999-2003, eight were service-related complaints. The remaining complaints were billing and other non-service issues.

FPUC does not have a written procedure for handling customer complaints. The company uses a customer record information system, which allows employees the ability to

document each customer interaction. The small size of each division office allows employee and management to closely interact with customers who have issues or complaints. If a customer service representative is unable to resolve an issue with the customer, the complaint is escalated up the management chain of command.

FPUC does not participate in formal customer satisfaction or survey programs. The company believes that it is not necessary since FPUC's small size allows the employees to directly interact with its customers. This interaction allows company employees to directly observe customer attitude and perception of the company's overall performance.

In January 2004, the corporate Customer Relations Department began monitoring customer complaints, FPSC complaints, and customer comments. The corporate office is using this data to evaluate customer satisfaction within each division. The data will be analyzed and shared with the divisions for internal assessment of customer satisfaction and improvement opportunities. The company states that maintaining this information has made it easier to query and document customer complaints and comments.

4.0 CONCLUSIONS

4.0 Conclusions

This section of the report presents BRR staff's conclusions and recommended solutions for improving the company's reliability performance.

4.1 Conclusion 1

FPUC Electric Reliability Performance Has Declined During the Period 1999-2004.

During the review period, FPUC's service reliability indices have been declining. While the company has reduced the number of outages over the period, it has experienced an increase in the SAIDI and SAIFI indices and inconsistent CAIDI results. This shows the average minutes of system interruption has increased and the frequency of outages per customers served has increased.

BRR staff believes that the company should place greater emphasis on improving the service reliability within both divisions. Sections 4.2 through 4.5 discuss areas where the company should place a greater concentration. Implementing these recommendations, along with an overall focus on reliability within the company, should provide FPUC's customers with more reliable service.

4.2 Conclusion 2

FPUC Electric Divisions Operate Autonomously, Which Creates Operating Inefficiencies and Hinders Improved Service Reliability.

Until the 2004 FPSC rate case, the two divisions of FPUC have maintained separate rate bases and operated more as sister organizations than two divisions within the company's Electric Unit. In the 2004 rate case the Commission combined the divisions' separate rate bases into a single company rate base at the company's request.

Ensuring the two divisions are managed similarly and customer's needs are met uniformly is essential. The company needs to provide the two divisions with written goals and objectives clearly outlining a unified approach in FPUC's electric unit. In years past, each division's management has independently set the overall division goals, Five-Year Plans, and annual budgets. This divisional independence has allowed inconsistencies in how the Northeast and Northwest divisions operate.

Going forward, the company should consider unifying the management and operational approaches within the divisions. As a combined company, the two Division Directors, along with corporate management, should evaluate the overall needs of the company and determine how best to implement the needs within both divisions. Combining goals, creating an overall electric Five-Year Plan, and aligning budget needs for both divisions would move the company

toward operating as a unified electric unit. This focus will allow the company to unify efforts in improving service to its customers.

4.3 Conclusion 3

Consolidated Written FPUC Operating and Maintenance Procedures Are Needed.

FPUC's two electric divisions have management teams that are hands-on and work directly with service employees. This direct involvement can ensure the work is completed to the standards set by management and the company. This direct management involvement allows for verbal communications of expectations, which can be an effective means of reinforcing written company policy and expectations.

However, in many cases, FPUC does not have written policies and procedures outlining the expectations of company management and the company for reliability-related activities. Without written procedures clearly communicating the policy, the potential for misunderstanding and miscommunications increases. Staff notes that either exception to company policies or failure to adhere to them was involved in the Bristol outages in 2004. According to the company, efforts are in progress to document written procedures for certain functional operations. Staff recommends that FPUC continue to document its maintenance processes with written procedures wherever possible.

4.4 Conclusion 4

Consolidated Written FPUC Goals and Objectives for Improving Service Reliability are Needed.

FPUC does not currently set expected improvement goals when planning and implementing a reliability improvement program or initiative. The company states that the overall goal is to improve the quality of service and reduce reliability indices. FPUC also does not forecast annual budget dollars for these programs. The company cannot determine how successful a program or initiative has been based on the dollars spent.

Sound management policy dictates that a company should set achievement goals and evaluate whether the money being spent and the work being performed provide an overall benefit to its customers and the organization. Making sure adequate resources are being given to the reliability initiative is one component for ensuring positive results. Tracking and evaluating results are equally important components in determining the success of the initiative. BRR staff recommends that FPUC budgets, tracks, and evaluates the resources allotted to reliability initiatives to ensure overall improvement goals are achieved.

4.5 Conclusion 5

Written FPUC Record Retention Procedures and Standards are Needed.

FPUC currently has written a policy for the retention of company financial records, but has not extended these policies to include the retention periods for company operational records. The lack of this documentation creates uncertainty as to the length FPUC operational records for maintenance activities should be retained.

Without these records, the company is left with little proof of previously completed operational and maintenance activities. In addition, the company may be required to undertake extensive and burdensome research efforts to recapture this data for future use. During this review, BRR staff found that important operational records necessary to document FPUC's inspection of distribution facilities were lost, misplaced or destroyed. FPSC and FERC regulations allow the company to determine the length of retention of distribution and transmission inspections and oil testing data. Therefore, FPUC does not appear to have violated regulatory rules.

However, BRR staff believes FPUC management should identify the specified retention period for different types of operational data and document these requirements in the current written retention policy. This action would ensure that employees understand, and could research if necessary, the length of retention for different operational data and know when certain records could be purged.

5.0 COMPANY COMMENTS



5.0 Company Comments

This chapter contains company comments in response to staff conclusions presented in chapter 4.0 Conclusions. Comments are included verbatim as presented to staff by the company.

5.1 Conclusion 1

FPUC electric reliability has declined during the period 1999 – 2004.

Company Comment – Based solely on the results from the indices, it does appear that there has been some decline during the period indicated. The comments shown in 5.2 – 5.5 will further address items which will assist in improving the indices in the future. It should also be noted that FPUC was granted a base rate increase and consolidated rates in 2004 which will further allow the improvement in the indices.

5.2 Conclusion 2

FPUC electric divisions operate autonomously which creates operating inefficiencies and hinders improved service reliability.

Company Comment – During the 2004 rate proceeding, the two division's base rates were consolidated. Prior to the consolidation the two divisions operated independently based upon the different rate structures and the difference in the two divisions. One division being primarily an inland rural area and the other being primarily a coastal urban area defined different operating procedures. Efforts were begun prior to the rate proceeding to consolidate operations and some progress has been made. However, with years of experience in operating separately, there have been some challenges to developing operating standards that incorporate the needs of both divisions.

FPUC disagrees that the differences have created operating inefficiencies and hindered improved service reliability over the years. Weather influences during certain years and the small customer base have a larger impact on service reliability indices than does operational differences. However, a continued effort is underway to continue to consolidate operating procedures and the establishment of service reliability goals in both divisions as was indicated in the rate proceeding.

5.3 Conclusion 3

Consolidated written FPUC operating and maintenance procedures are needed.

Company Comment – FPUC is currently developing consolidated operating and maintenance procedures. Significant consolidated procedures such as a Vegetation Management Program, Overhead Line Inspection Program and Underground Line Inspection Program have already been developed and submitted in conjunction with this report. Additional procedures are being evaluated and will be developed and consolidated for use in both divisions. As was noted in this conclusion, the outages in Bristol were considered avoidable but were caused by human error and not by the lack of operating procedures. Also, included in the procedures will be the requirement for documentation and retention of those documents.

5.4 Conclusion 4

Consolidated written FPUC goals and objectives for improving service reliability are needed.

Company Comment – FPUC has tracked reliability results for many years and has attempted to improve these standards during that time. Reliability tracking was begun before FPUC was required to track such data. Beginning in 2005, goals and objectives for improving service reliability standards will be developed and analyzed going forward. The additional requirements for tracking budget and actual expenditures of reliability improvement programs are being studied at this time. Under the current financial tracking system, the mechanism for budgeting and tracking expenditures for these programs is not available. Information on the status of this matter will be available later in 2005.

5.5 Conclusion 5

Written FPUC record retention procedures and standards are needed.

Company Comment – The FPUC record retention procedure and standards will be developed and followed in the future. During the review, there was an abundance of documentation provided that maintenance programs were in place and the work was being conducted. It is noted that some documentation was not available which enforces the need for these procedures and standards that will be developed.

6.0 APPENDIX

APPENDIX 1

Glossary of Terms

Arresters - or Surge Arrester - Device which protects lines and equipment against voltage surges caused by lightning, equipment switching or abnormal system conditions. The surge arrester is connected from the line to ground to provide a conducting path. This limits the voltage on lines or equipment and dissipates excess energy harmlessly.

CAIDI - Customer Average Interruption Duration Index - Measure of the average duration of interruptions experienced by the customers interrupted.

Capacitor - An electrical device that maintains or increases voltage in power lines and improves the efficiency of the electrical system by reducing inductive losses that produce wasted energy.

CEMI5 - Customers Experiencing Multiple Interruptions Index - Measure of the total number of customers experiencing more than a certain number of sustained outages relative to the total number of customers served.

CSR - Customer Service Representative

Distribution Feeder Line - A distribution feeder is the main circuit or trunk line from which taps carry electricity to residential and commercial customers.

Feeder - An electric circuit with limited capacity extending from the main distribution line feeder, usually supplying a small number of customers. (Often used interchangeably with "circuit".)

FPSC - Florida Public Service Commission

Interruption - Interruption of electric service to a customer, usually of one minute or more in duration. Usually excludes Momentary Interruptions, defined below.

kva - Kilovolt-amperes - A unit of electrical force equal to 1,000 volt-amperes. The kilovolt-ampere is the practical unit of apparent power.

L-BAR - Average length of all service interruptions experienced, this measure is not weighted for the number of customers effected by an interruption.

Line Transformer - A garbage can-sized cylindrical object generally attached to power poles that step down primary distribution voltage to secondary distribution voltage for delivery to individual customers.

MAIFI - Momentary Average Interruption Frequency Index - Measure of the total number of customer momentary interruption events relative to the total number of customers served.

Momentary Interruption - Interruption of service to a customer of less than one minute in duration. Usually represents loss of power for a fraction of a second caused by transient conditions, such as tree limbs or animals contacting with components of the distribution system. Momentaries can cause air conditioners to quickly shut off then back on, and many digital clocks to reset to 12:00,

N - Number of Interruptions, as reported in the Distribution Service Reliability Report to the FPSC.

O & M - Operations and Maintenance

Outage - In a strict sense regarding electric distribution, the condition of a piece of equipment being out of service, which may not result in service interruption to customers, for example through the use of circuit breakers and switching. Term is also used more loosely as interchangeable with interruption of service.

Padmount Transformers - Transformers located on the ground on concrete pads and protected by steel cabinets. Used in conjunction with underground distribution systems.

SAIDI - System Average Interruption Duration Index - Measure of the average duration of interruptions for the total number of customers served by the system. Conceptually equivalent to CMI/C and SU.

SAIFI - System Average Interruption Frequency Index - Measure of the average frequency of interruptions for the customers served by the system.

Substation - An assemblage of equipment designed for switching, changing or regulating the voltage of electricity. This definition does not include service equipment, line transformers, line-transformer installations, or minor distribution or transmission equipment. High electrical voltages from 69,000 to 765,000 volts are required to move electricity through transmission lines across great distances. Electric motors and appliances are not designed to use electricity at these high voltages, so voltage reductions must take place at a substation near a community served or along the transmission line serving a very large customer.

Transformer - An electromagnetic device that increases the voltage of electricity as it leaves the power plant so it can travel long distances or lowers the voltage of electricity for distribution.

Trouble Ticket - Generic term referring to a trouble call received from a customer, and the resulting work order to resolve the problem. Trouble tickets may or may not involve an interruption of service.