Review of Florida's Investor-Owned Electric Utilities' Service Reliability In 2005

Florida Public Service Commission

Division of Economic Regulation
Division of Regulatory Compliance and Consumer Assistance
Division of Competitive Markets and Enforcement

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Section 1. Introduction

Rule 25-6.0455, Florida Administrative Code (F.A.C.), requires each investor-owned electric utility in Florida to file a Distribution Service Reliability Report each year. In March 2006, the five investor-owned electric utilities (IOUs) filed their reports with reliability data for 2005. The IOUs' Distribution Service Reliability Reports, in combination with the utilities' responses to staff data requests, staff audits of utility operations, and reliability information gleaned from customer complaints filed with the Commission, are used to evaluate each utility's distribution reliability performance.

The purpose of this report is threefold:

1. Update the Commission regarding staff's review of the IOUs' distribution service reliability performance in 2005.

2. Provide a review of 2004 and 2005 hurricane impacts on distribution service reliability and the Commission's actions taken to ensure utilities storm-harden electric infrastructure and otherwise prepare for storm events in order to reduce storm-related outages.

3. Identify focus areas for future utility performance reviews, including the Commission's actions to improve performance through storm preparation activities.

The Commission derives its authority to require reports from electric utilities to assure the development of adequate and reliable energy grids from Section 366.05(7), Florida Statutes (F.S.). The Commission has jurisdiction over electric utilities for the purpose of requiring reliability within a coordinated grid, for operational as well as emergency purposes, pursuant to Section 366.04(2)(c), F.S.

Section 2. Reliability Indicators Used in this Report

1. *Customer Average Interruption Duration Index* (CAIDI) is an indicator of average interruption duration, or the time to restore service to interrupted customers. CAIDI is calculated by dividing the total system customer minutes of interruption by the number of interrupted customers.

2. *System Average Interruption Frequency Index* (SAIFI) is an indicator of average service interruption frequency experienced by customers on a system. It is calculated by dividing the number of service interruptions by the number of customers served.

3. *System Average Interruption Duration Index* (SAIDI) is a composite indicator of outage frequency and duration and is calculated by dividing the customer minutes of interruptions by the number of customers served on a system. Mathematically, SAIDI is the product of SAIFI and CAIDI. Thus, a SAIDI of 100 may be achieved by a SAIFI of 1 and a CAIDI of 100, or by a SAIFI of 1.25 and a CAIDI of 80.

4. *Momentary Average Interruption Event Frequency Index* (MAIFIe) is an indicator of average frequency of momentary interruptions or the number of times there is a loss of service of less than one minute. MAIFIe is calculated by dividing the number of momentary interruption events recorded on primary circuits by the number of customers served.

5. *Customers Experiencing More Than Five Interruptions* (CEMI5) measures the percent of customers that have experienced more than five service interruptions.

6. *Three Percent Feeder Report* is an identification of the three percent of the utility's feeders with the highest number of feeder breaker lockouts. An index of these data is created for inter-utility comparative purposes known as "Recurring Feeders." Recurring Feeders is the number of feeders that are listed more than once in three consecutive years on an IOU's "Three Percent Feeder Report" divided by the total number of feeders on the Three Percent Feeder Report. The report is a measure of the tendency for a subset of feeders to sustain a relatively high number of outages compared to other feeders on the system over time.

7. *Percent of Total Outage Events for the Primary Causes* is an identification of the percent of total outages listed by cause (vegetation, animal, lightning, weather, etc.).

Section 3. Executive Summary

The impact of the 2004 and 2005 hurricanes and tropical storms on Florida's electric utilities and their customers has substantially changed the way electric utilities and the Commission measure electric distribution reliability performance. Prior to 2004, the focus for distribution reliability assessment was based upon adjusted reliability data, or data that excluded the impact of a variety of events considered outside the control of the utility, such as outages associated with named storms (hurricanes and tropical storms). Rule 25-6.0455, F.A.C., prior to its June 2006 revision, required only adjusted reliability data to be reported by investor-owned electric utilities in the state. In 2004 and 2005, however, a very large percentage of customers' service interruption minutes were caused by hurricanes and tropical storms. Moreover, nationally recognized experts in meteorology predict a 15-20 year increase in hurricane and tropical storm activity. The Commission has recognized the importance of this changed circumstance with the modification of Rule 25-6.0455, F.A.C., in June 2006 to require utilities to include both unadjusted and adjusted reliability data in their annual reports. Both types of measures are seen as providing valuable performance information. The adjusted data shows the level of performance under more controlled circumstances, reflective of the vast majority of days in the reporting period. The unadjusted data provides an indication of the robustness of the distribution system under much more volatile circumstances, when lengthy customer outages may result from hurricanes or tropical storms. This report of 2005 distribution reliability performance addresses three subject areas:

(1) Reliability performance based on adjusted reliability data, reflecting the level of distribution reliability during non storm periods,

(2) Reliability performance based on unadjusted reliability data, reflecting the level of distribution reliability performance year-round, including the impact of named storms (Commission staff gathered unadjusted data for 2005 via data requests sent to the utilities since such data was not required by rule during that period), and

(3) Actions the Commission has taken to ensure utilities storm-harden electric infrastructure and otherwise prepare for storm events in order to reduce storm-related outages.

<u>Reliability Performance Based on Adjusted Data</u>

In assessing the distribution reliability of Florida's electric IOUs based on adjusted data (excluding the impact of certain types of outages identified in Rule 25-6.0455(2), F.A.C.) from 2000 to 2005, staff observes, in general, relative stability in the reliability indices. However, as recently as 1997, several of the key indices for the state's largest electric utilities Florida Power & Light Company (FPL) and Progress Energy (PEF) were at their historically highest level (indicating higher outage times, longer durations, and, hence, lower levels of reliability performance). While the investor-owned utilities appeared to be providing reasonably reliable service in general in 2005, there are areas where additional reliability gains may be achieved. The following ongoing Commission oversight is recommended:

- Continue to monitor the unfavorable trend in Gulf Power Company's (GULF's) CAIDI and SAIDI performance indices (measures of service interruption duration) from 2001 through 2005 and the twenty-five percent increase in GULF's SAIFI (a measure of service interruption frequency) in 2005. GULF maintains its SAIFI and SAIDI in 2005 were impacted by residual effects of hurricanes and that these "carry over" effects were not reflected in the exclusions taken for these events. Staff will review GULF's efforts to better quantify and mitigate these after-storm efforts on a going-forward basis.

- Continue to monitor actions taken by Tampa Electric Company (TECO) to increase vegetation management and substation maintenance aimed at improving the utility's unfavorable trend in its CAIDI and SAIDI.

- Monitor actions taken by FPL to reduce the frequency of customer interruptions, relative to other investor-owned utilities, as indicated by their SAIFI and CEMI5 performance indices. These indices appear to have improved (decreased) for FPL in 2004 and 2005 based on the reported data, but it is not clear yet whether the apparent improvement is real or a reflection of lengthy hurricane outage exclusion periods during those years.

<u>Reliability Performance Based on Unadjusted Data</u>

The hurricane and tropical storm events of 2005, like those of 2004, impacted service reliability to most of Florida's electric utility customers exponentially more than all other reliability impacts combined for the year. Unlike 2004, when service reliability impacts were spread somewhat evenly across a variety of utilities throughout the state, service reliability impacts in 2005 were limited primarily to two utilities' service areas (FPL's and GULF's). The storm effects (wind, rain, flooding) varied company by company, depending on the severity and path of each storm.

Hurricane Wilma had the greatest service reliability impact on the state in 2005, and the impact was disproportionately felt by FPL's customers. Approximately 3.2 million FPL customers were without electric service due to Hurricane Wilma for a period ranging from one to eighteen days, resulting in an average restoration time (CAIDI) of 4,586 minutes (76.4 hours). The impact of Hurricane Wilma on PEF and TECO was significantly less, resulting in an average restoration time of less than two hours for these companies.

The level of service reliability impacts in 2005 caused by hurricanes and tropical storms compared to reliability impacts due to other causes was dramatic for certain utilities. FPL's storm SAIDI was 4,632 minutes, or 66 times the utility's adjusted SAIDI of 70 minutes. GULF's storm SAIDI was 3,240 minutes, or 28 times the utility's adjusted SAIDI of 115 minutes. GULF's service reliability in 2005 was impacted primarily by Hurricanes Dennis and Katrina.

Storm Threat Response - Storm Preparation and Hardening

The impact of the 2004-2005 hurricane seasons clearly demonstrates that the reported distribution reliability indices based on unadjusted data cannot be solely relied upon to gauge service reliability. In 2006, the Commission embarked on a multi-pronged approach to harden the state's electric infrastructure in order to minimize storm outages and restoration times. These measures include:

- Requiring electric IOUs to increase the frequency and rigor of wood pole inspections, including load assessments related to pole attachments;

- Requiring electric IOUs to file plans addressing ten separate initiatives to storm harden the electric distribution and transmission system, including more rigorous or expanded vegetation management practices, post-storm forensic data collection and analysis, transmission inspections, increased storm preparation response coordination with local governments, and collaborative storm-hardening research with universities and research organizations;

- Requiring electric IOUs to conduct pre-storm season preparedness and recovery planning;

- Proposing rules governing construction standards of electric utility overhead and underground distribution facilities to facilitate the development and construction of a more storm resilient electric utility infrastructure; and

- Monitoring the data and information voluntarily provided by the municipal and rural electric utilities in the area of wood pole inspections, storm hardening initiatives, and pre-storm season preparedness and recovery planning.

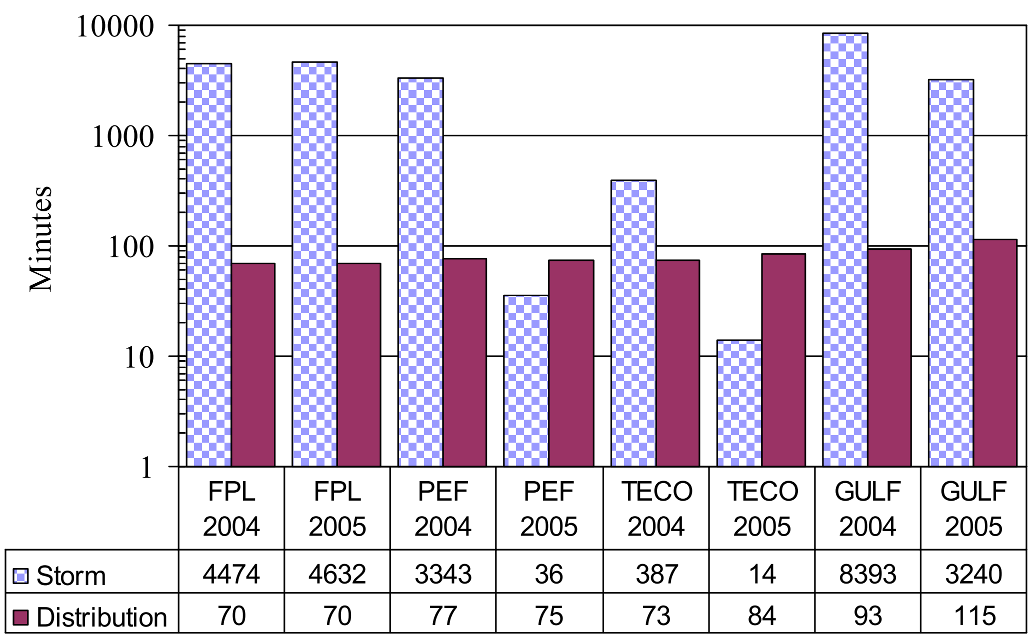
These measures are at various stages of implementation. Developing each measure and evaluating the results coming from their implementation will help ensure the Commission's goal of reducing outages and restoration times is achieved in an efficient and cost-effective manner. On October 30, 2006, the Commission conducted an informal workshop during which utilities and interested parties discussed the information the utilities will provide by March 1 of each year to facilitate a thorough, yet timely, review of the previous year's storm hardening activities and distribution reliability performance results. Staff expects the ongoing dialogue initiated at the workshop will result in comprehensive electric utility storm preparedness and reliability performance filings on March 1, 2007.

Section 4. Storm Impacts on Service Reliability (Unadjusted Data)

The hurricane and tropical storm events of 2005, like those of 2004, impacted service reliability to most of Florida's electric utility customers exponentially greater than all other reliability impacts combined for the year. Unlike 2004, when service reliability impacts were spread somewhat evenly across many utilities throughout the state, service reliability impacts in 2005 were limited primarily to two utilities' service areas (FPL's and GULF's). The storm effects (wind, rain, flooding) varied company by company, depending on the severity and path of each storm.

Figure 4-1 summarizes the effect of the major storms on distribution reliability as measured by the System Average Interruption Duration Index (SAIDI) for 2004 and 2005. The SAIDI is a composite indicator of service interruption duration and frequency. The SAIDI based on hurricane and tropical storm effects only (Storm SAIDI) is compared to the SAIDI based on the exclusion of hurricane and tropical storm outages and other excludable events per the rule (Adjusted SAIDI). As shown by Figure 4-1, the 2004 hurricanes and tropical storms had a tremendous effect on service interruption duration and frequency for all four utilities (note that the Y-axis is exponential). A similar impact was experienced in 2005 for FPL and GULF. The impact of the storms on service reliability varied company by company depending on the severity and path of each storm during the active hurricane years of 2004 and 2005.

Figure 4-1
Storm Effects and Non-Storm Distribution Reliability
SAIDI for 2004-2005



The 2004 Storm SAIDIs for all companies shown is significantly higher than the Adjusted SAIDIs. This observation corresponds with the fact that, within a six week period from

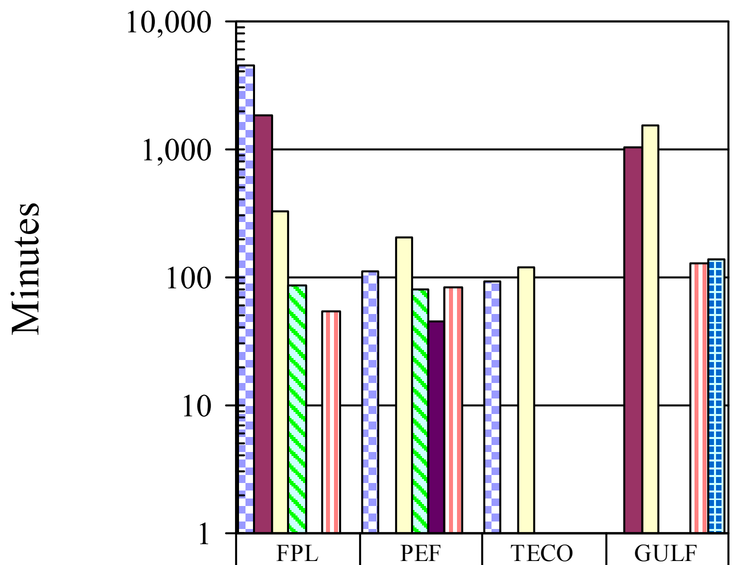
August 13 to September 25, 2004, Hurricanes Charley, Frances, and Jeanne overlapped in the central part of the state. Also, in September 2004, Hurricane Ivan severely affected service availability in the northwestern panhandle region.

For FPL and GULF, the 2005 Storm SAIDIs are exponentially higher than their 2005 Adjusted SAIDIs, but the 2005 Storm SAIDIs for PEF and TECO show relatively small storm impacts. This variation reflects a shift in the storm tracks in 2005, which were generally further south and into the Gulf of Mexico than the 2004 storms. On July 10, 2005, Hurricane Dennis made landfall on Santa Rosa Island in the Florida Panhandle after passing over Cuba and the Gulf of Mexico, wreaking havoc on GULF's service territory. Also in July, Hurricane Emily formed in the central Atlantic but took a more southerly and westerly route into the Gulf along Venezuela's Caribbean coast, ultimately making landfall on Mexico's Yucatan Peninsula. Although each of these storms brought heavy rainfall, flooding, and high winds to South Florida, their damage was relatively minor. Hurricane Katrina formed as a Tropical Depression over the Bahamas on August 23, 2005, and continued to move toward Florida, becoming a hurricane only two hours before making landfall between Hallandale Beach and Aventura, Florida, on the morning of August 25. Hurricane Katrina weakened over land, but caused widespread damages and outages in FPL's service territory. Katrina regained hurricane status about one hour after entering the Gulf of Mexico, going on to devastate New Orleans and much of Mississippi's coast and causing significant damage and outages in GULF's territory. In September, Hurricane Rita passed between Cuba and the Florida Keys, into the Gulf of Mexico, and made landfall in Texas. Late in the season, on October 24, 2005, Hurricane Wilma made landfall at Cape Romono, Florida, approximately 20 miles south of Naples, Florida, as a Category 3 hurricane. Moving from west to northeast, Hurricane Wilma raced across the state, causing extensive damage to FPL facilities from Palm Beach to Miami.

Average Storm Restoration Times - 2005

Figure 4-2 shows the effect of each storm on restoration times for FPL, PEF, TECO, and GULF in 2005. The effect is measured by the CAIDI (Customer Average Interruption Duration Index), the average time to restore service to interrupted customers. Hurricane Wilma had the greatest impact on FPL's service reliability. Approximately 3.2 million FPL customers were without electric service for a period ranging from one to eighteen days, resulting in an average restoration time of 4,586 minutes (76.4 hours). The impact of Hurricane Wilma on PEF and TECO was significantly less, resulting in an average restoration time of less than two hours for these two companies.

Figure 4-2
2005 Average Storm Restoration Time (CAIDI)



	FPL	PEF	TECO	GULF
Hurricane Wilma	4,586	110	94	
Hurricane Katrina	1,863			1,035
Hurricane Dennis	329	209	121	1,560
Hurricane Rita	88	82		
Hurricane Ophelia		45		
T.S. Arlene	55	84		129
T.S. Cindy				136

Section 5. Storm Threat Response - Storm Preparation and Hardening

On January 23, 2006, the Commission held a staff workshop to review damage to electric utility facilities resulting from the 2004-2005 hurricane seasons and to explore ways of minimizing future storm damage and reducing outages to customers. State and local government officials, independent technical experts, and Florida's electric utilities participated in the workshop. At the February 27, 2006, Internal Affairs, based on the comments received at the January 23, 2006, workshop, the PSC directed staff to initiate a series of actions to address the effects of extreme weather events on the electric infrastructure. This multi-pronged approach to address the need for a more storm-resistant electric system has resulted in the following Commission actions:

- <u>Required Eight-Year Wood Pole Inspection Cycles:</u> On February 27, 2006, the Commission issued Order No. PSC-06-0144-PAA-EI requiring investor-owned electric utilities to implement an eight-year wood pole inspection cycle.

- <u>Required Utility Storm Preparation Briefings, Initiated Storm Hardening Rulemaking, and Directed Staff Recommendation on Storm Plan Filings</u>: On February 27, 2006, the Commission determined at its Internal Affairs Meeting to

  1) Require all Florida electric utilities to provide a Hurricane Preparedness Briefing at the June 5, 2006, Internal Affairs.

  2) Initiate rulemaking to adopt construction standards more stringent than the National Electric Safety Code (later resulting in Docket No. 060173-EU) and to identify areas and circumstances where distribution facilities should be constructed underground (later resulting in Docket No. 060172-EU).

  3) Direct staff to file a recommendation to require investor-owned electric utilities to file storm preparation and hardening plans.

- <u>Required Specific Storm Plans from Electric IOUs</u>: On April 25, 2006, the Commission issued Order No. PSC-06-0351-PAA-EI directing Florida's electric utilities to file ten storm preparation and hardening plans by June 1, 2006, including the following:

  1) A three-year vegetation management cycle program for all distribution circuits or, provided a utility can provide adequate supporting cost and reliability data, a program with three year feeder trim cycles and lateral trim cycles longer than three years,
  2) A periodic audit of joint-use attachment agreements,
  3) A six-year transmission inspection program,
  4) A program to harden existing transmission structures,
  5) A transmission and distribution geographic information system,
  6) A system of post-storm data collection and forensic analysis,
  7) A plan to collect detailed outage data differentiating between the reliability performance of overhead and underground systems,

8) A plan to increase utility coordination with local governments,
9) A plan for collaborative research with universities and research organizations on the effects of hurricane winds and storm surges, and
10) A natural disaster preparedness and recovery program.

- Approved Rules on Storm Hardening for IOUs: At the June 20, 2006, Agenda, in Docket Nos. 060172-EU and 060173-EU, the Commission voted to propose rule amendments and additions to require utilities to storm harden their systems. On July 27, 2006, the Commission issued Order No. PSC-06-0632-PCO-EU, bifurcating rule proceedings for the electric IOUs and municipal electric utilities and rural electric utilities. On December 5, 2006, the Commission approved staff's recommendations to adopt rules containing certain revisions to its June 20, 2006, proposed amendments and additions for the IOUs. The rules require IOUs to file comprehensive storm hardening plans for review and approval by the Commission. The rules also require the costs of hardening the electric infrastructure to be reflected in the contribution-in-aid-of-construction (CIAC) charged for new underground facilities and conversions from overhead to underground. Differences in operational costs between overhead and underground facilities must also be included in CIAC calculations.

- Approved Storm Hardening Rules for Municipal Electric Utilities and Rural Electric Utilities: At a hearing on October 4, 2006, the Commission approved an alternative rule addressing storm hardening standards and reporting for municipal electric utilities and rural electric utilities.

- Required Specific Compliance Actions: At the August 29, 2006, Agenda Conference, the Commission addressed various compliance matters regarding the earlier regulatory actions it had taken with regard to the utilities' storm hardening plans and wood pole inspection requirements:

  1) In Docket No. 060198-EI, the Commission considered that the adequacy of the plans filed in response to Order No. PSC-06-0351-PAA-EI required additional data to be filed by PEF and GULF to support their vegetation management plans; later, after such supporting data was provided, the Commission determined the filings were satisfactory for initial implementation but also concluded that additional review of the cost effectiveness of the plans would be pursued in 2007.

  2) In Docket No. 060531-EU, the Commission required the electric IOUs to provide support for their plans to deviate in certain regards from the requirements of Order No. PSC-06-0144-PAA-EI, including their plans to exclude some poles from the eight-year wood pole inspection program and not excavate certain poles.

Each of the regulatory actions listed above are in various stages of implementation. Monitoring each storm hardening regulatory requirement and evaluating their implementation helps ensure the Commission's goal of reducing outages and restoration times is achieved in an efficient and cost-effective manner. On October

30, 2006, the Commission conducted an informal workshop during which utilities and interested persons discussed with Commission staff the storm hardening and reliability information the utilities will provide by March 1 of each year. The information is needed to facilitate a thorough, yet timely, review of the previous year's storm hardening activities and distribution reliability performance results. Also, information related to collaborative research projects with universities will be collected and reviewed in order to assure that the best methods of managing resources are identified and utilized. Staff expects the ongoing dialogue initiated at the workshop will result in comprehensive electric utility storm preparedness and reliability performance filings on March 1, 2007.

The City of North Miami (City) has protested Order No. PSC-06-0351-PAA-EI regarding FPL's Vegetation Management Plan. The City opposes FPL's planned six-year trim cycle for lateral circuits, claiming that a six-year cycle is inadequate within the City limits. A Commission hearing is scheduled for February 5, 2007.

Finally, the municipal electric utilities and cooperative electric utilities voluntarily reported their storm-hardening plans after the Commission issued Order No. PSC-06-0351-PAA-EI requiring investor-owned electric utilities to report their storm hardening plans. The municipal electric utilities' storm initiatives are summarized in Appendix E, and the rural electric cooperative utilities' storm initiatives are summarized in Appendix F. In general, these other utilities appear to be following a track of storm hardening in a manner similar to the investor-owned electric utilities.

Section 6: Service Reliability Reviews of Individual Utilities (Adjusted Data)

In this section, staff presents its review of the electric IOUs' 2005 distribution reliability performance based on the reliability indices appearing in each IOU's 2005 Annual Distribution Reliability Report. The data provided in the IOU Annual Distribution Reliability Reports are adjusted for the outage events identified in Rule 25-6.0455(2) (predating the revisions of June 2006). These data reflect the outage exclusions allowed by the rule, including the outages associated with the 2005 hurricanes and tropical storms. In addition, this review is based in part on information collected through data requests, management reviews, reliability data audits, and customer complaints. Each of these data collection tools is discussed in greater detail below.

- **Annual Distribution Reliability Reports** – Reliability report data filed by the investor-owned electric utilities is the primary basis for evaluating normal distribution reliability. The report includes each of the indices identified earlier in Section 2. The indices summarize reliability performance in terms of frequency and duration of service interruptions and momentary interruptions on a system-wide basis, a geographic division basis, or on an event basis. The data lends itself well for inter-utility comparisons and trend analysis.

- **Data Requests** – A review of the data presented in the utilities' reliability reports does not provide a full understanding of the reasons why trends or relationships between the data exist. Staff issues data requests and meets with each of the electric utilities to gather the necessary information.

- **Management Review** – To ensure that each utility has designed, constructed, and maintained its distribution facilities to appropriate standards, the Commission also periodically conducts reliability audits that focus on review of utility management of reliability programs. In 1997, a distribution reliability audit conducted by the Commission highlighted many areas that needed improvement. A follow-up audit of FPL and PEF conducted in 2000 revealed that these two utilities had markedly improved their levels of reliability within a relatively short period (1997 to 1999). In late 2004, the Commission initiated a quality of service management audit of TECO, GULF and FPUC. The audit is similar to the one conducted in 1997, but broader in scope to include transmission as well as distribution functions. The audit of TECO and FPUC was completed in 2005. Audit reports of FPL and PEF (restricted to pole inspection, vegetation management, and lightning protection management) were completed in June 2005. The audit of GULF was completed in March 2006. Staff will monitor the implementation of the recommended improvement actions identified in those reports.

- **Vegetation Management Program Review** – Physical contact between trees and electric distribution facilities are one of the primary causes of electric service interruptions. Pursuant to actions taken by the Commission to address hurricane related storm hardening initiatives, staff has significantly increased the monitoring of the utilities' vegetation management programs. A summary of each company's vegetation management program is shown in Appendix D. In response to Commission Order No. PSC-06-0351-PAA-EI, TECO and FPUC have committed to transition to a three-year cycle of vegetation management for all distribution circuits. FPL, PEF, and GULF have committed to a three-year average trim cycle on distribution feeders and a five-year cycle (PEF) or six-year cycle (FPL and GULF) on laterals. These three utilities' vegetation management plans incorporate incremental activities other than additional cycle trimming, such as programs to remove hazardous trees from locations adjacent to electric utility rights-of-way which they believe will reduce storm-related service interruptions.

- **Reliability Data Audits** – In order to ensure the integrity of the data used to calculate the reliability indices, staff periodically conducts data audits. Comprehensive data audits were conducted for the 2002 and 2003 report data. No such data audits were conducted for 2004 and 2005 report data. In 2007, staff plans to conduct a limited scope audit on the 2006 report data of at least one major investor-owned utility.

- **Customer Complaints –** The 1997 distribution reliability audit was initiated based on increases in the number of distribution service reliability complaints logged with the Commission's Division of Consumer Affairs. The data used for evaluating changes in customer complaint rates are the service reliability complaints per 10,000 customers (see Appendix B).

<u>Summary of Individual Company Service Reliability Reviews</u>

A review of the reliability indices for the period of 1998 through 2005 for each investor-owned utility is detailed in Subsections A through E. A summary of the trends and observations drawn from each investor-owned utility's adjusted data is as follows:

- **FPL** – FPL's reported SAIFI is 1.15 interruptions, the highest among the five IOUs in 2005; however, its CAIDI of 60 minutes is the lowest among the five IOUs in 2005. FPL's SAIDI shows a steady trend, with the reported SAIDI in the 68-70 range from 2000 through 2005. Its CEMI5 data show an improving (decreasing) trend in the last three years, from 3.3 percent of its customers experiencing more than five interruptions in 2003, to 1.9 percent in 2005. However, the 2005 CEMI5 level is still higher than that of PEF and GULF. Based on FPL's relative underperformance in SAIFI and CEMI5, the Commission should carefully monitor the frequency of FPL's service interruptions.

- **PEF** – For the five-year period of 2001-2005, PEF shows an improvement (decrease) in both its SAIDI and its SAIFI. PEF's reported CEMI5 is 1.0 percent, the lowest among the five IOUs in 2005. PEF's improving reliability performance may be due in part to the utility's practice of setting multi-year goals for reliability improvement.

- **TECO** – At 1.02 interruptions per customer, TECO's reported SAIFI is the lowest among the five IOUs in 2005. However, TECO's CAIDI and SAIDI data continue to show an unfavorable (increasing) trend since 2001. TECO recognizes the more recent trend indicates a decline in reliability and, as a result, is taking action to increase vegetation management and substation maintenance. To improve its outage management performance, TECO has increased staffing in its Trouble Department by 15 percent in 2006.

- **GULF** – GULF's SAIFI remained relatively steady in the 2001-2004 period, with a four-year average of 0.91 interruptions per customer. However, its SAIFI in 2005 increased by twenty-five percent from the previous four-year average to 1.14. GULF's CAIDI and SAIDI data also show an unfavorable (increasing) trend in the 2001-2005 period. This unfavorable trend was discussed in a staff management review of GULF's electric service quality, completed in March 2006. GULF maintains its SAIFI and SAIDI in 2005 were impacted by the residual effect of hurricanes (dead tree limbs falling into lines months after a hurricane).

- **FPUC** – FPUC's reported SAIDI for 2005, 68 minutes per customer, is the lowest among the five IOUs. Because it is a smaller system, FPUC's SAIDI can change significantly from year to year. FPUC's SAIFI indicates improvement from 2003 to 2005 while its CAIDI shows no clear trend. For most years, FPUC's CAIDI ranges from 60 to 65 minutes.

In June 2006, the Commission amended Rule 25-6.0455, F.A.C., Annual Distribution Reliability Report. Beginning with the March 2007 distribution service reliability reports, the investor-owned utilities are required to provide both adjusted as well as unadjusted data in their filings. The adjusted data will continue to be used, as in prior years, to represent distribution service reliability exclusive of events which may be, in large measure, outside of the utilities' control, like hurricanes and tropical storms. However, evaluating the unadjusted reliability data is important in drawing inferences about the impact of major storms and other uncontrollable events on service reliability and providing a starting point for evaluating the effectiveness of storm hardening initiatives. These changes will be reflected in the 2007 distribution reliability review of 2006 utility operations.

A. Florida Power and Light (FPL)

System Average Indicators

Figure 6-1 shows the distribution service reliability measured by FPL's adjusted SAIDI (minutes of interruption per customer). From 2000 through 2005, FPL's SAIDI remained steady, within the 68-70 range.

Figure 6-2 and Figure 6-3 show the SAIFI (number of interruptions per customer) and CAIDI (minutes of customer restoration time per interrupted customer), respectively. FPL achieved its best SAIFI in 2005, with a system average of 1.15 interruptions per customer. FPL's best CAIDI was 50.5 minutes in 2003.

Figure 6-1
SAIDI (FPL)

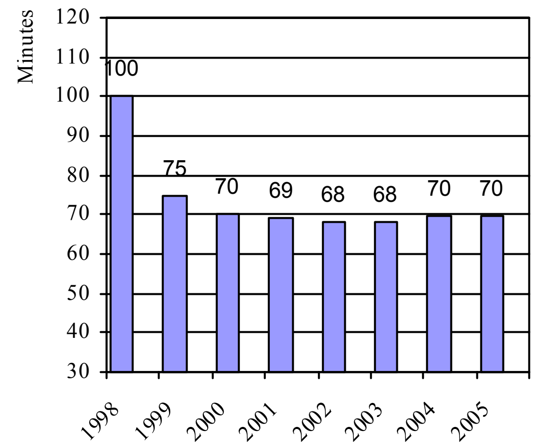


Figure 6-2
SAIFI (FPL)

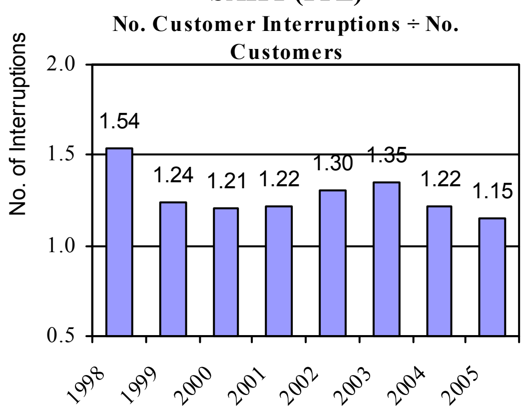
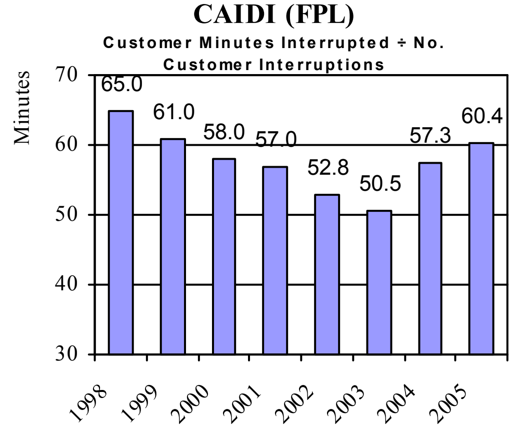


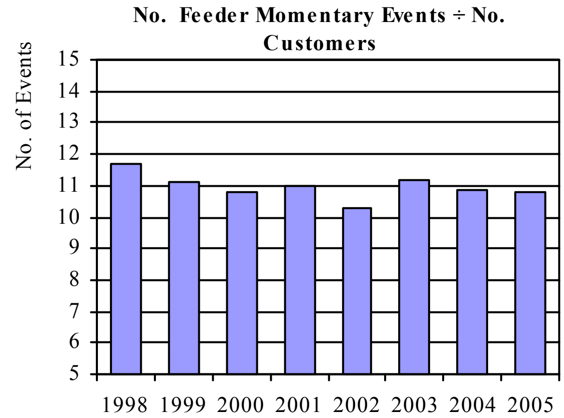
Figure 6-3
CAIDI (FPL)



After a comprehensive review by the Commission in 1997, FPL took several actions to address its reliability performance. Both SAIFI and CAIDI improved significantly in the years subsequent to 1998, an improvement which is also reflected in its composite SAIDI indicator. In recent years, FPL's focus has been improving its SAIFI. FPL's reported SAIDI in 2005, at 70 minutes per customer, is the lowest among the five IOUs during that year.

Figure 6-4 shows the average frequency of feeder momentary events measured by MAIFIe. The data do not indicate significant improvement or deterioration in the 1999-2005 period. Because this indicator captures only momentary events that affect the feeders resulting from substation operations, customers located near the end of a below-average feeder likely experience a higher number of momentary interruptions than the MAIFIe indicates. For other reported indicators, Appendix A shows the comparison of data reported by FPL and the other four companies.

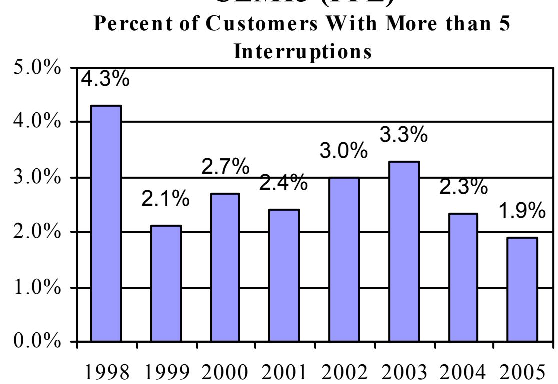
Figure 6-4
MAIFIe (FPL)



Other Reliability Indicators

Frequent outage problems experienced by a subset of customers indicates an opportunity for improvement. Such problems may be masked by an over-reliance on reviewing system averages exclusively; therefore, other indicators are used. Figure 6-5 shows CEMI5, or the percent of customers experiencing more than five interruptions per year, from 1998 through 2005. For FPL, the data suggest an improvement from 3.3 percent in 2003 to 1.9 percent in 2005. However, FPL's 2005 CEMI5 is still higher than that of PEF and GULF.

Figure 6-5
CEMI5 (FPL)



FPL's Treasure Coast Management Region, which includes Martin, St. Lucie, Okeechobee, Indian River, and portions of Glades Counties, has shown the worst reliability indicators among its sixteen management regions. Among the contributing factors cited by FPL are growth, weather, vegetation, and the long circuits needed to serve this large geographic area. In 2003, in its Treasure Coast region, FPL initiated upgrade activities that included adding new feeders, creating new feeder ties, and increased vegetation management activities. The CEMI5 for Treasure Coast has improved from 7.3 percent in 2003 to 4.2 percent in 2005.

FPL's Three Percent Feeder Report contains a list of the top three percent of feeders with the most feeder outage events. The list for 2005 contains 87 feeders, of which 66 feeders (76 percent) had not been on the list in the five years preceding 2005. Of the 87 feeders on the list, 52 (60 percent) have four feeder outage events recorded during the year; the remaining 35 feeders (40%) have five or more feeder outage events recorded during the year.

Further review of the feeders with five or more feeder outage events reveals an opportunity for future reliability improvement. Based on the number of feeder outage events recorded during the year (N) and the number of times the feeder had been on the list in the last five years before 2005, the worst feeder is Natoma 805235. Natoma 805235 had eleven recorded outage events and appears on FPL's Three Percent Feeder Report in two of the last five years. However, this feeder's average restoration time is relatively short, with CAIDI of 12.5 minutes. Of the remaining 34 feeders with N greater than or equal to 5, six feeders have an N of 7; one of them had been on the list twice before and five of them had not been on the list before. Natoma 805235, and others like it which appear on the three percent feeder list multiple times, may be identified for targeted corrective action.

FPL's actions to address the frequent outage problem include two programs: Outlier and Multiple Interruptions. The Outlier program addresses customers experiencing excessive interruptions and/or momentaries. The Multiple Interruption program concentrates on devices experiencing multiple interruptions during specific timeframes. Additionally, FPL also cited other programs such as vegetation, cable rehabilitation, and thermovision. Over time, if these programs are implemented effectively, the indicators such as CEMI5 and the percent of feeders repeatedly on the worst performing feeder list should improve.

Named Storms and Other Excluded Events

Adjusted distribution reliability indices exclude the outage events identified in Rule 25-6.0455, F.A.C. Excludable events fall into three general categories: generation and transmission, named storms, and other events excludable under Rule 25-6.0455, F.A.C.

For 2005, FPL reported that 3.2 minutes of service interruption associated with transmission events (inclusive of generation events) were excluded from SAIDI. This number does not include minutes of service interruptions associated with transmission outage events resulting from named storms. All such service interruption minutes during named storms are considered distribution service outage minutes due to the coincident occurrence of storm damages and related outages to both transmission and distribution assets.

Hurricane Wilma's reliability impact on FPL's system and customers was greater than the other four named storms of 2005 combined, as is shown in the table below.

Named Storm	Max. Gust within FPL Territory	Number of Distribution Poles Replaced	SAIDI (Minutes)	CAIDI (Minutes)
Hurricane Wilma	120 mph	11,371	3,841	4,586
Hurricane Katrina	92 mph	1,086	754	1,863
Hurricane Dennis	44-69 mph	109	34	329
Hurricane Rita	42-58 mph	81	2	88
T.S. Arlene	58 mph	0	1	55
Non-FPL Poles		-5,200		
Total FPL in 2005		7,447	4,632	3,346

FPL excluded 2.9 minutes of SAIDI in 2005 identified as other events. Other events included planned events (1.7 minutes) and tornados (1.2 minutes).

Lessons Learned and Actions Taken Due to 2004 - 2005 Hurricane Seasons Reliability Impacts

Hurricane Wilma (2005) was the most costly hurricane for FPL in the 2004-2005 hurricane seasons. FPL's restoration costs associated with the impact of Hurricane Wilma were more than twice as much as the second most costly hurricane, Hurricane Jeanne. The high restoration costs and extended outages associated with Hurricane Wilma and prior hurricanes have impacted customer perception of FPL's reliability, especially in Palm Beach, Broward, and Dade Counties, where Wilma had its greatest impact and created high levels of customer outages. As discussed in last year's review, the reliability indices for these three counties historically tended to be better than FPL's system averages. The primary lesson learned as a result of studying the 2004-2005 hurricane impacts is that storm hardening in Florida is essential, no matter whether recent hurricane seasons have been mild or severe. Given Florida's geographical exposure to powerful storms, the state must be constantly prepared for the devastating consequences of hurricanes. The balance between developing a robust distribution system and incurring the costs of doing so will be a matter of ongoing concern and deliberation. Our review of unadjusted reliability indices in accordance with revised Rule 25-6.0455, F.A.C., can be expected to reveal relevant information about reliability performance, especially in those years with significant storm activity.

After the 2004 storm season, FPL identified two key areas to improve its hurricane outage restoration practice. First, FPL determined to improve its communication with stakeholders by improving collaboration with communities and Emergency Operations Centers (EOC's) on restoration priorities and providing more timely and effective information on restoration status. Second, FPL decided to better manage its restoration efforts. FPL established three restoration focus areas, including improved storm logistics (quicker staging site set-up, housing availability/location, material delivery, fueling), improved field communications (enhanced satellite and wireless communication technology), and improved workforce management (acquisition, tracking and management of external resources, field damage patrols, forensics team damage collection). After the 2005 storm season, FPL filed its Storm Secure Plan in an effort to address the storm hardening of its infrastructure. In addition, FPL reported that it is also addressing several system enhancements associated with tracking status of critical infrastructure facilities, its damage forecasting model, and its outage communication system. These actions taken by FPL in response to storm threats are consistent with the regulatory actions taken by the Commission as identified in Section 5 of this report.

B. Progress Energy Florida, Inc. (PEF)

System Average Indicators

Figure 6-6 shows service reliability as measured by PEF's adjusted SAIDI (minutes of interruptions per customer). From 2000 through 2005, PEF's SAIDI has improved, from 101 in 2000 to 75 in 2005.

Figure 6-7 and Figure 6-8 show PEF's adjusted SAIFI (number of interruptions per customer) and CAIDI (minutes of customer restoration time per interrupted customer), respectively. PEF achieved its best (lowest) SAIFI in 2005, with a system average of 1.12 interruptions per customer. PEF's best CAIDI was 64.7 minutes in 2004.

Figure 6-6
SAIDI (PEF)
Customer Minutes Interrupted ÷ No. Customers

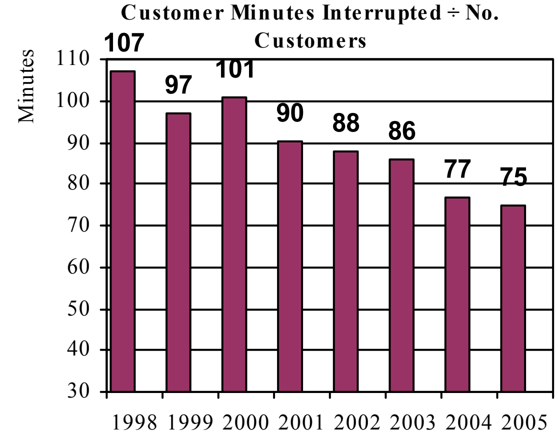


Figure 6-7
SAIFI (PEF)
No. Customer Interruptions ÷ No. Customers

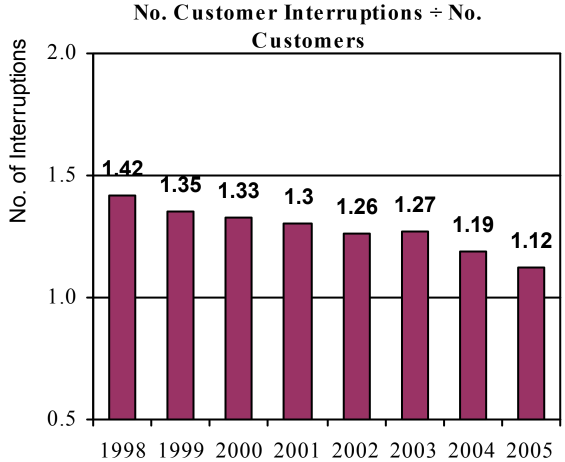


Figure 6-8
CAIDI (PEF)
Customer Minutes Interrupted ÷ No. Customer Interruptions

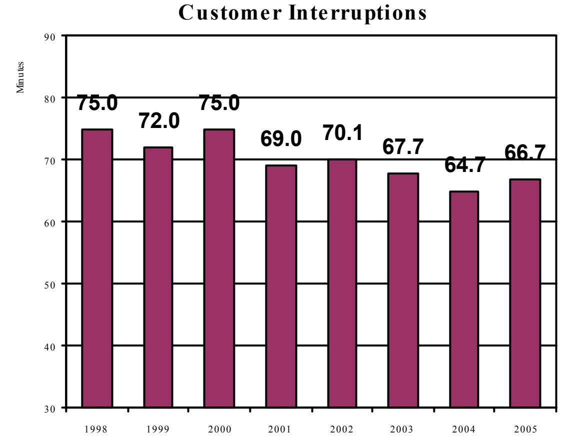
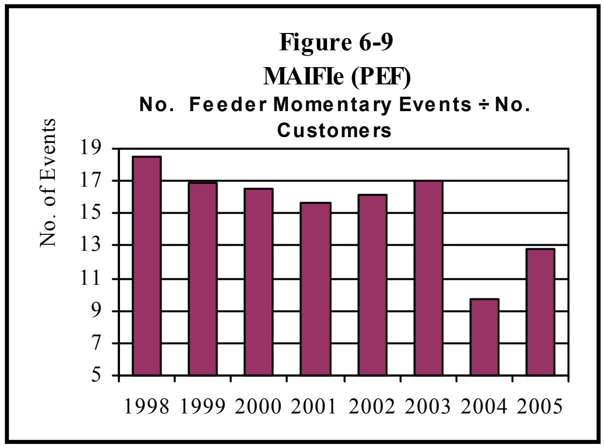
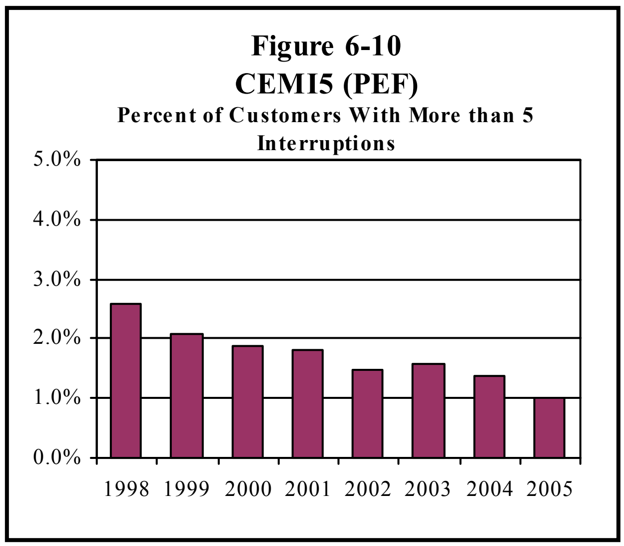


Figure 6-9 shows PEF's average frequency of feeder momentary events, or MAIFIe. The data show some improvement in 2004 and 2005. As discussed previously, customers located near the end of a below-average performing feeder likely experience a higher number of momentary interruptions than MAIFIe indicates. For other reported indicators, Appendix A shows the comparison of data reported by PEF and the other four companies.



<u>Other Reliability Indicators</u>

Frequent outage problems experienced by a subset of customers may be masked by system averages. Figure 6-10 shows PEF's CEMI5, or the percent of customers experiencing more than five interruptions a year, from 1998 through 2005. The data suggest an improvement from 2.6 percent in 1998 to 1.0 percent in 2005. PEF's CEMI5 for 2005 is the lowest among the four IOU's that report this percentage.



PEF's Three Percent Feeder Report contains a list of the top three percent of feeders with the most feeder outage events. The list for 2005 includes 37 feeders, of which 21 feeders (57%) had not been on the list in the last five years before 2005. Of the 37 feeders on the list, 34 (92%) have four or fewer feeder outage events recorded during the year, the remaining three feeders (8%) have five or more feeder outage events recorded during the year.

<u>Named Storms and Other Excluded Events</u>

Adjusted distribution reliability indices exclude the outage events identified in Rule 25-6.0455, F.A.C. Excludable events fall into three general categories: generation and transmission, named storms, and other events excludable under Rule 25-6.0455, F.A.C.

PEF had no generation events which resulted in service interruptions in 2005. Transmission outages accounted for 9.4 minutes excluded from PEF's SAIDI. This number does not include transmission outage events during named storms or tornadoes. Hurricane Dennis impacted PEF's system and customers more so than any of the other four named storms in 2005, as shown in the table below.

Named Storm	Number of Distribution Poles Replaced	Minutes excluded from SAIDI	Minutes Excluded from CAIDI
Hurricane Dennis	31	20	209
Hurricane Wilma	25	13	110
Hurricane Rita	0	1.5	82
Hurricane Ophelia	0	0.3	45
T.S. Arlene	0	1.4	84
Total PEF in 2005	56	36	142

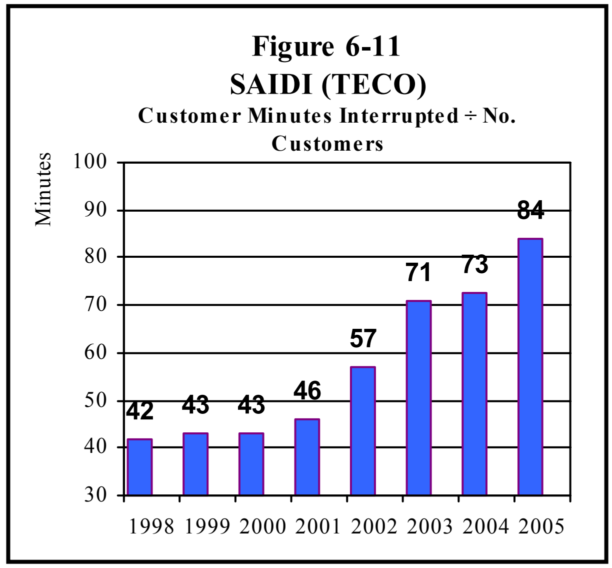
PEF excluded 13.0 minutes of SAIDI in 2005 identified as other events. Other events include planned events (8.2 minutes) and tornadoes (5.7 minutes).

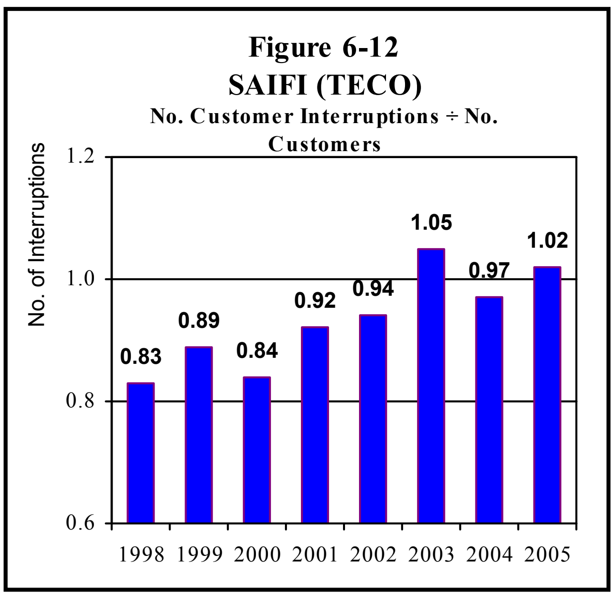
C. Tampa Electric Company (TECO)

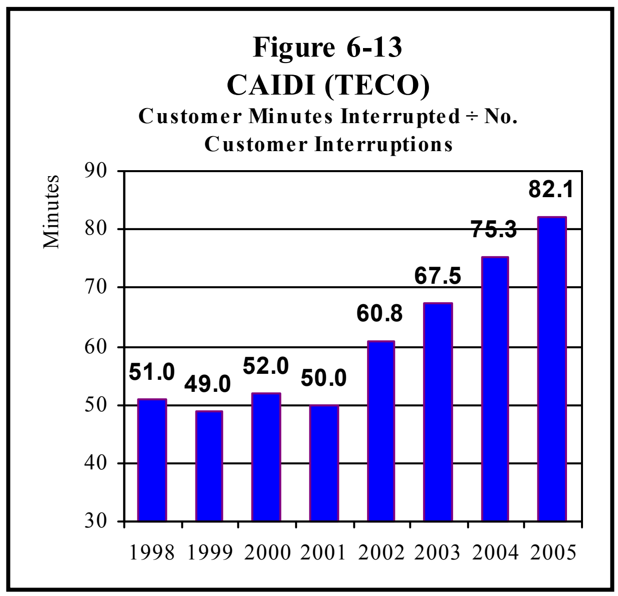
System Average Indicators

Figure 6-11 shows the distribution service reliability measured by TECO's adjusted SAIDI (minutes of interruption per customer). From 2001 through 2005, SAIDI increased from 46 minutes to 84 minutes.

Figure 6-12 and Figure 6-13 show the SAIFI (number of interruptions per customer) and the CAIDI (minutes of customer restoration time per interrupted customer), respectively. It appears that TECO's unfavorable trend in its SAIDI is mainly due to its CAIDI, which increased from 50 in 2001 to 82 in 2005. TECO's SAIFI remains relatively steady in the 2001-2005 period, with a five-year average of 0.98 interruptions per customer per year.



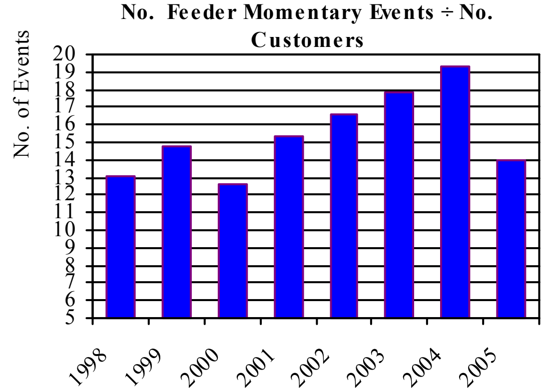




TECO's increase in SAIDI and CAIDI in 2002 and 2003 may be due in part to an information system upgrade completed in late 2001. TECO recognizes the recent increasing trend indicates a decline in reliability and is taking action to increase vegetation management and substation maintenance. A focus on reducing the duration of outages has been supplemented by a 15 percent increase in staffing in TECO's Trouble Department, which the company expects will have a favorable impact on CAIDI and SAIDI.

Figure 6-14 shows the average frequency of feeder momentary events measured by MAIFIe. The data show an unfavorable trend from 2000 to 2004, followed by an improvement in 2005. As discussed previously, customers located near the end of a below-average feeder likely experience a greater number of momentary interruptions than MAIFIe indicates. For other reported indicators, Appendix A shows the comparison of data reported by TECO and the other four companies.

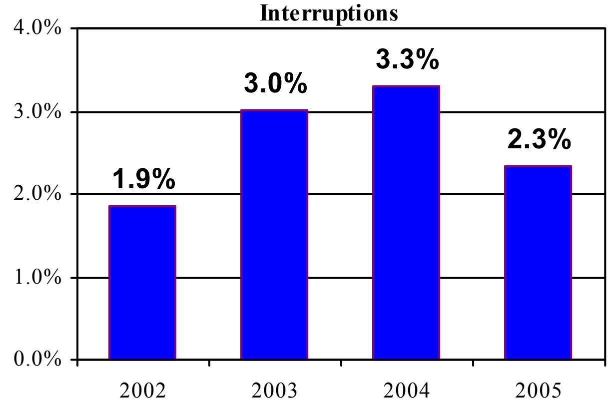
Figure 6-14
MAIFIe (TECO)
No. Feeder Momentary Events ÷ No. Customers



<u>Other Reliability Indicators</u>

Frequent outage problems experienced by a subset of customers may be masked by system averages. Figure 6-15 shows CEMI5, or the percent of customers experiencing more than five interruptions a year, from 2002 through 2005. The data suggest an unfavorable trend from 2002 to 2004, and an improvement in 2005.

Figure 6-15
CEMI5 (TECO)
Percent of Customers With More than 5 Interruptions



TECO's Three Percent Feeder Report includes a list of the top three percent of feeders with the most feeder outage events. The list for 2005 contains 22 feeders, of which 16 feeders (73%) had not been on the list in the last five years before 2005. Of the 22 feeders on the list, 15 feeders (68%) have four or fewer feeder outage events recorded during the year, the remaining seven feeders (32%) have five or more feeder outage events recorded during the year.

<u>Named Storms and Other Excluded Events</u>

Adjusted distribution reliability indices exclude the outage events identified in Rule 25-6.0455, FAC. Excludable events fall into three general categories: generation and transmission, named storms, and other events excludable under Rule 25-6.0455, F.A.C.

TECO had no generation outage events which resulted in service interruptions in 2005. Transmission outages resulted in an exclusion of 16 minutes from TECO's 2005 SAIDI. This number does not include transmission outage events during named storms or tornados. The impact of named storms to TECO's system in 2005 is shown in the table below.

Named Storm	Number of Distribution Poles Replaced	Minutes Excluded from SAIDI	Minutes Excluded from CAIDI
Hurricane Wilma	2	7.0	94
Hurricane Dennis	9	6.7	121
Total TECO in 2005	11	13.7	106

Based on TECO's data, exclusion due to other events lowered TECO's SAIDI by 0.73 minutes in 2005. All such minutes were related to planned events.

D. Gulf Power Company (GULF)

System Average Indicators

Figure 6-16 shows the distribution service reliability measured by GULF's adjusted SAIDI (minutes of interruptions per customer). From 2001 through 2005, SAIDI increased from 79 minutes to 115 minutes.

Figure 6-17 and Figure 6-18 show the SAIFI (number of interruptions per customer) and CAIDI (minutes of customer restoration time per interrupted customer), respectively. It appears that GULF's unfavorable trend in its SAIDI appears to be mainly due to its CAIDI, which increased from 87 in 2001 to 101 in 2005. GULF's SAIFI remains relatively steady in the 2001-2004 period, with a four-year average of 0.91. Its SAIFI in 2005 is a 25 percent increase from its four-year average.

Figure 6-16
SAIDI (GULF)
Customer Minutes Interrupted ÷ No. Customers

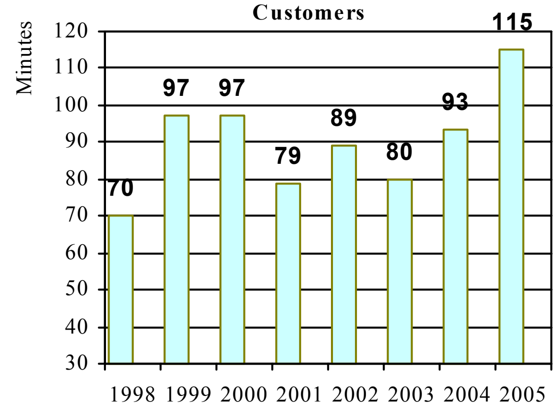


Figure 6-17
SAIFI (GULF)
No. Customer Interruptions ÷ No. Customers

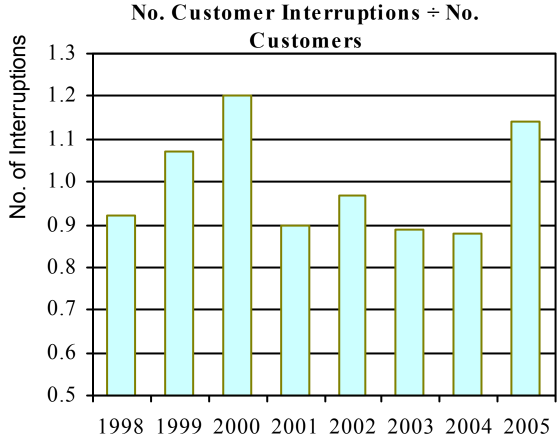
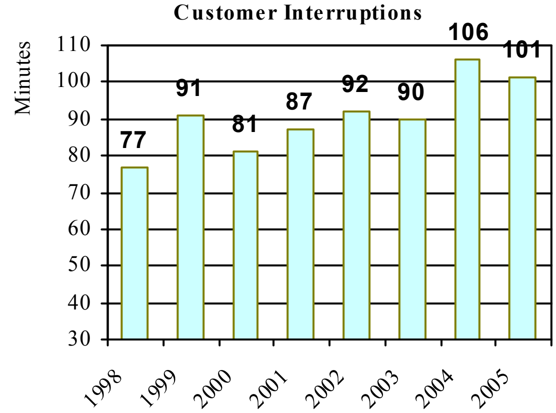


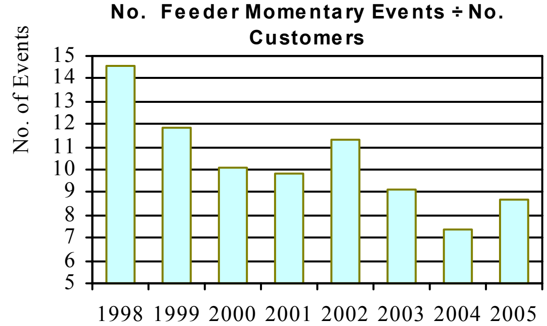
Figure 6-18
CAIDI (GULF)
Customer Minutes Interrupted ÷ No. Customer Interruptions



This unfavorable trend is also discussed in a management review of GULF's electric service quality completed in March 2006. GULF maintains it historically has had a low SAIFI, but its SAIFI and SAIDI in 2005 were impacted by the residual effect of hurricanes. Despite 2005 increases in its SAIFI and CAIDI, the number of GULF's service reliability complaints logged by the Commission declined in 2005 (see Appendix B).

Figure 6-19 shows the average frequency of feeder momentary events measured by GULF's MAIFIe. The data show some improvement from the 1998-2001 period, but do not indicate significant improvement or deterioration in the 2003-2005 period. Customers located near the end of a below-average feeder likely experience a higher number of momentary interruptions than MAIFIe indicates. For other reported indicators, Appendix A shows the comparison of data reported by PEF and the other four companies.

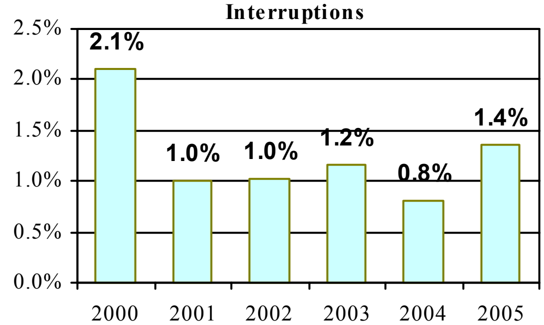
Figure 6-19
MAIFIe (GULF)
No. Feeder Momentary Events ÷ No. Customers



Other Reliability Indicators

Frequent outage problems experienced by a subset of customers may be masked by system averages. Figure 6-20 shows CEMI5, or the percent of customers experiencing more than five interruptions a year, from 2000 through 2005. The data suggest an improvement from 2.1 percent in 2000 to 1.4 percent in 2005.

Figure 6-20
CEMI5 (GULF)
Percent of Customers With More than 5 Interruptions



GULF's Three Percent Feeder Report includes a list of the top three percent of feeders with the most feeder outage events. The list for 2005 contains eight feeders, and none of them had been on the list in the five years preceding 2005. None of the eight feeders have five or more feeder outage events recorded during the year.

Named Storms and Other Excluded Events

Adjusted distribution reliability indices exclude the outage events identified in Rule 25-6.0455, F.A.C. Excludable events fall into three general categories: generation and transmission, named storms, and other events excludable under Rule 25-6.0455, F.A.C.

GULF had no generation events which resulted in service interruptions in 2005. Because of a data collection problem which GULF discovered this year, the number of excludable minutes associated with transmission events outages in 2005 could not be accurately determined.

The impact of each of the two hurricanes and the two tropical storms to GULF's system in 2005 is shown in the table below.

Named Storm	Number of Distribution Poles Replaced	SAIDI (Minutes)	CAIDI (Minutes)
Hurricane Dennis	641	2,579	1,560
Hurricane Katrina	49	648	1,035
T.S. Arlene	2	7.6	129
T.S. Cindy	0	6.4	136
Total for GULF in 2005	692	3,240	1,359

Other events accounted for an exclusion of 48 minutes from GULF's adjusted SAIDI in 2005. Planned events account for an exclusion of 41 minutes, and extreme weather events causing activation of county emergency operations centers accounted for seven excluded minutes.

E. Florida Public Utilities Company (FPUC)

<u>System Average Indicators</u>

Figure 6-21 shows the distribution service reliability measured by FPUC's adjusted SAIDI (minutes of interruptions per customer). Because it is a smaller system, FPUC's SAIDI can change significantly from one year over another.

Figure 6-22 and Figure 6-23 show the SAIFI (number of interruptions per customer) and CAIDI (minutes of customer restoration time per interrupted customer), respectively. FPUC's SAIFI appears to follow a cyclical pattern which indicates an improvement from 2003 to 2005. FPUC's CAIDI show no clear trends. For most years, FPUC's CAIDI is within 60 to 65 minutes.

Figure 6-21
SAIDI (FPUC)
Customer Minutes Interrupted ÷ No. Customers

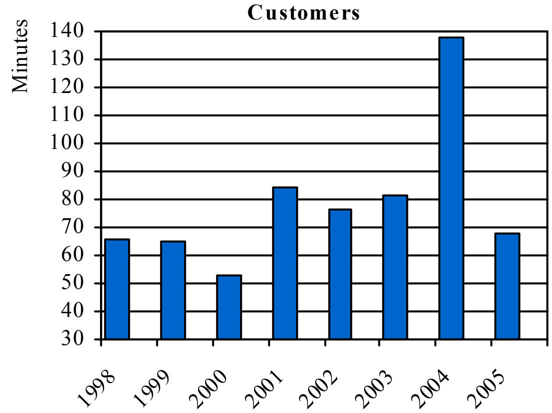


Figure 6-22
SAIFI (FPUC)
No. Customer Interruptions ÷ No. Customers

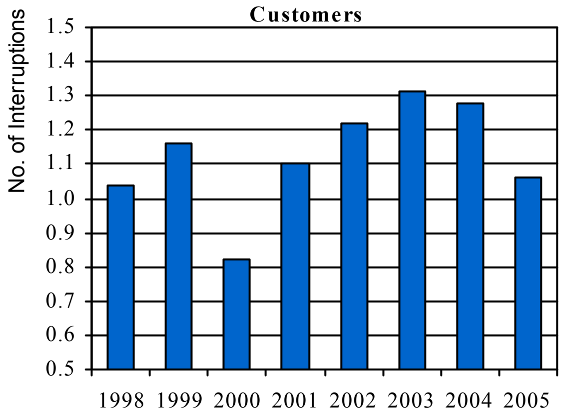
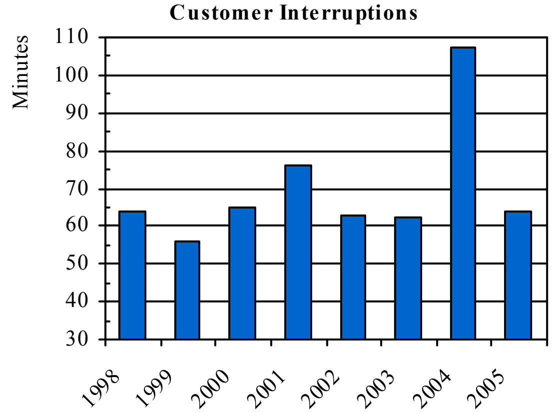


Figure 6-23
CAIDI (FPUC)
Customer Minutes Interrupted ÷ No. Customer Interruptions



Factors cited by FPUC for SAIFI improvement in 2004-2005 include increased tree trimming, the installation of five additional three phase reclosers, the replacement of underground cable, and improved overhead maintenance.

FPUC has not reported MAIFIe and CEMI5 because it does not have an automated data collection system necessary to capture such data. FPUC relied on a manual method for outage data collection. In 2006, FPUC's Northwest Division (Marianna) began using an automated outage management system based on a GIS database that includes an accurate customer count. The GIS database is updated daily by its customer billing system. Calls are logged in its outage management system, including restoration time and outage cause. Field restoration is handled as it has been in the past, except its outage management system now makes predictive indications regarding the location of the interruption. FPUC's Northeast Division (Fernandina Beach) will continue processing outages by the manual method.

FPUC's Three Percent Feeder Report for 2005 contains two feeders. Neither feeder had been on the list in five years preceding 2005 nor had five or more feeder outage events been recorded during the year.

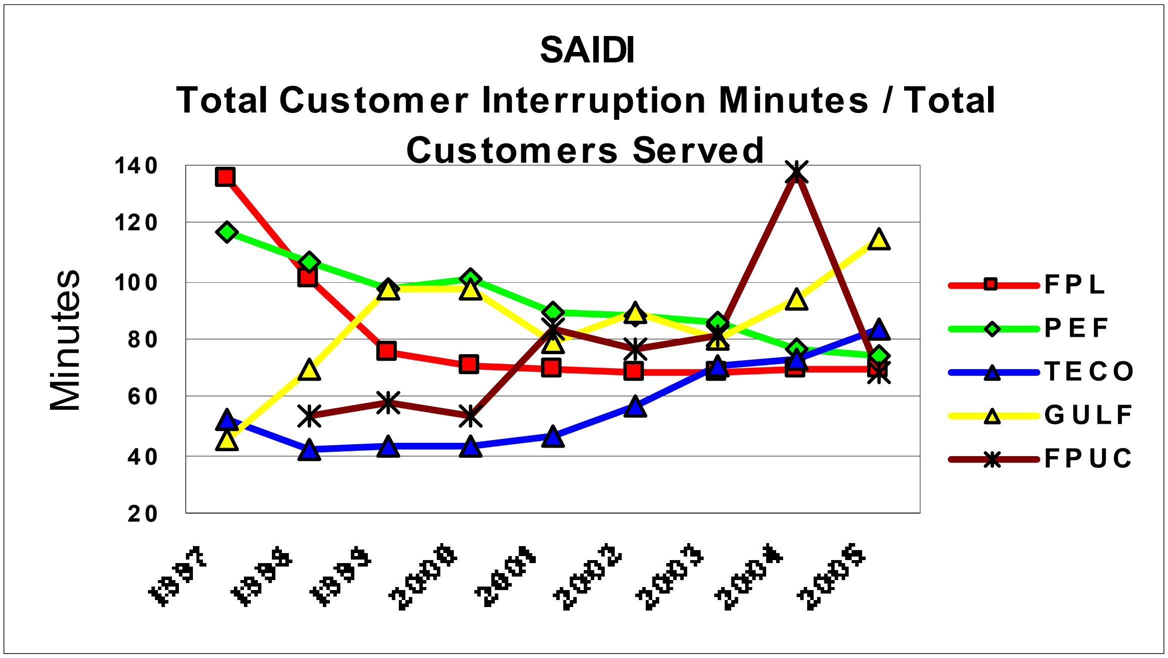
Named Storms and Other Excluded Events

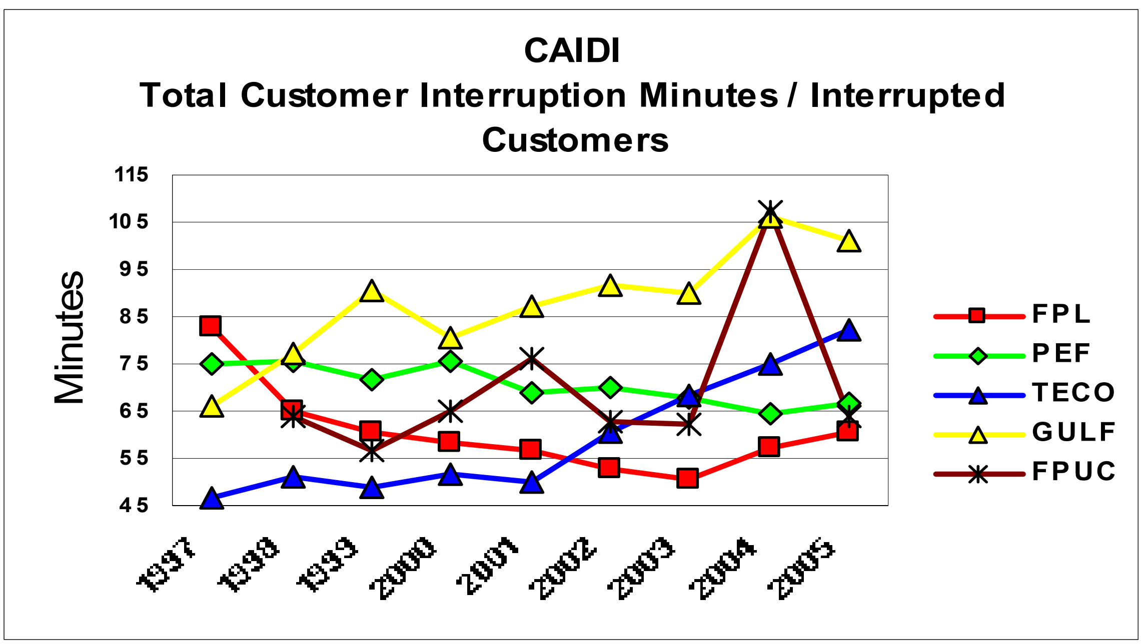
Adjusted distribution reliability indices exclude the outage events identified in Rule 25-6.0455, FAC. Excludable events fall into three general categories: generation and transmission, named storms, and other events excludable under Rule 25-6.0455, F.A.C.

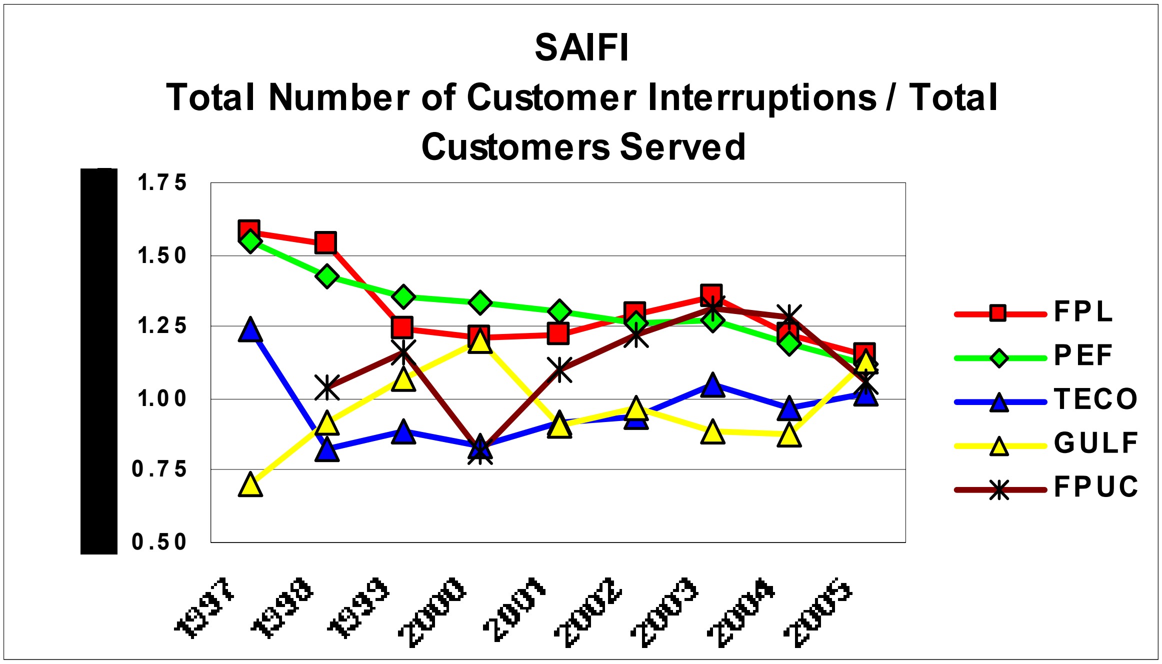
FPUC had no generation events that resulted in service interruptions in 2005. Transmission-related outages resulted in 81 minutes excluded from FPUC's SAIDI. This number does not include transmission outage events during named storms or tornadoes. FPUC's Northeast Division is the only division that has transmission facilities. The excluded number of minutes associated with transmission events appears relatively high because the Northeast Division's electrical system is small compared to the other IOUs. A single generation or transmission outage can completely disable the division's system.

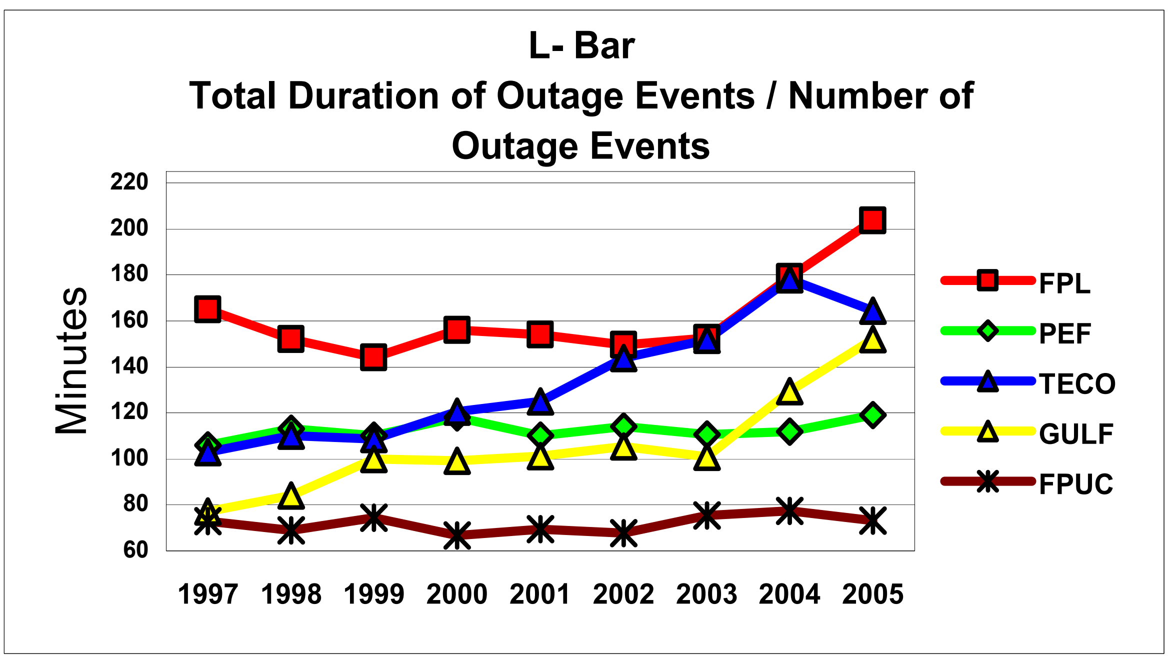
Section 7. Appendices

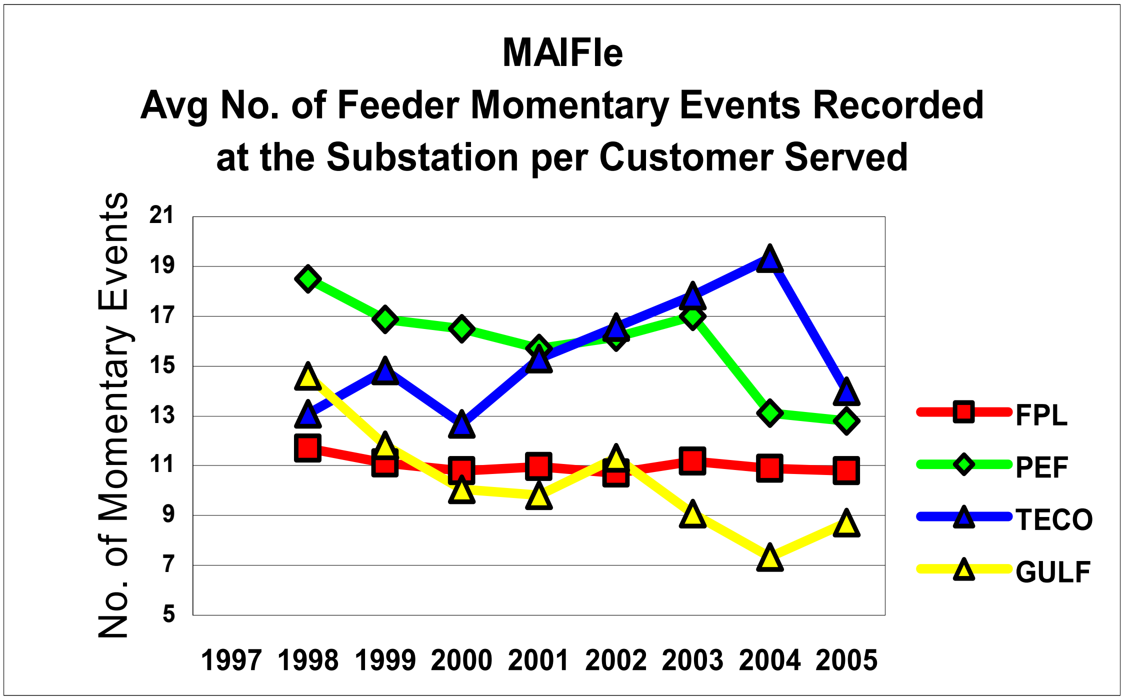
Appendix A: Reliability Indices (Adjusted Date) – Interutility Trend Comparisons

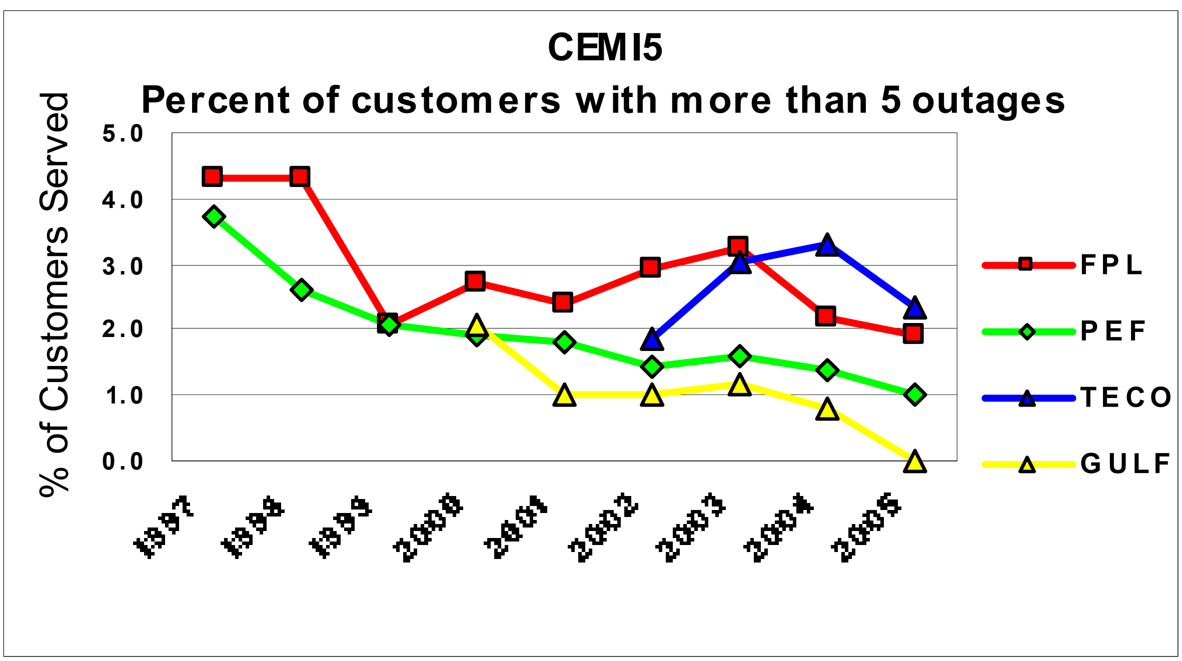





SAIFI
Total Number of Customer Interruptions / Total Customers Served
1.75
1.50
1.25
1.00
0.75
0.50
1997
1998
1999
2000
2001
2002
2003
2004
2005
FPL
PEF
TECO
GULF
FPUC

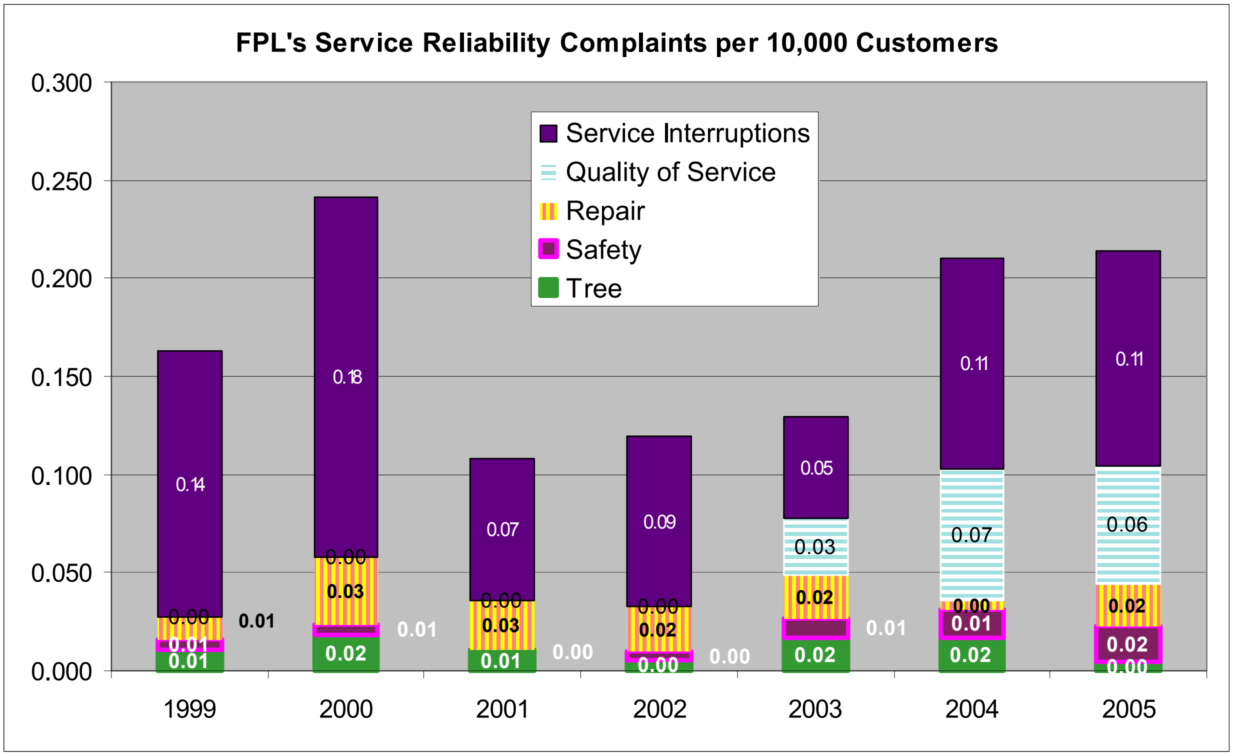

L- Bar
Total Duration of Outage Events / Number of Outage Events
Minutes
220
200
180
160
140
120
100
80
60
1997
1998
1999
2000
2001
2002
2003
2004
2005
FPL
PEF
TECO
GULF
FPUC

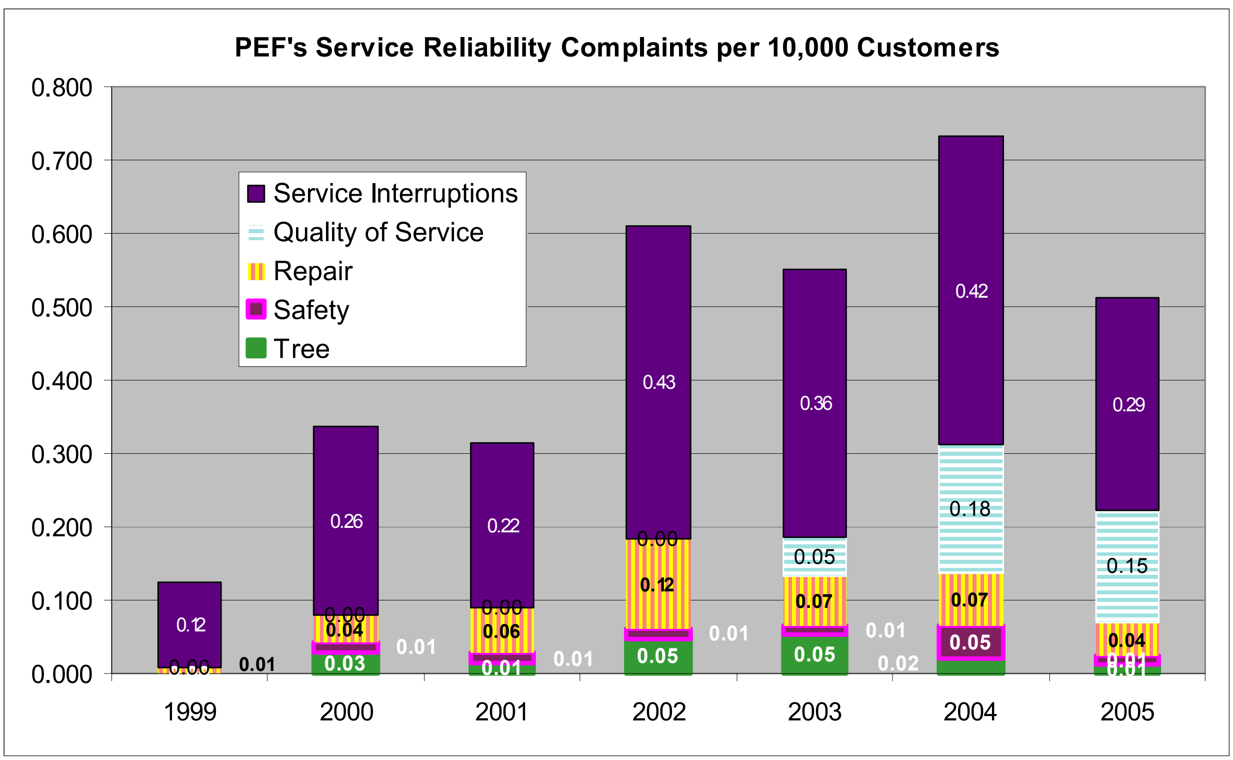

MAIFIe
Avg No. of Feeder Momentary Events Recorded at the Substation per Customer Served
No. of Momentary Events
21
19
17
15
13
11
9
7
5
1997 1998 1999 2000 2001 2002 2003 2004 2005
FPL
PEF
TECO
GULF

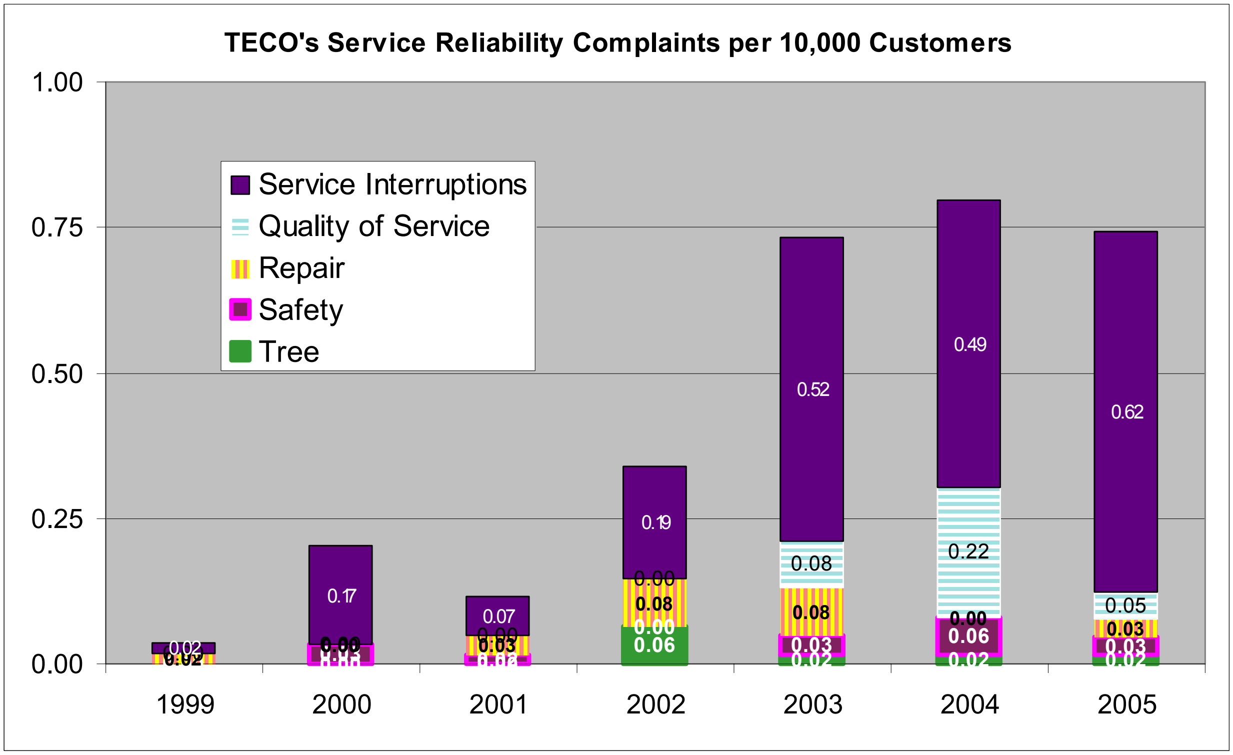

CEMI5
Percent of customers with more than 5 outages
% of Customers Served
5.0
4.0
3.0
2.0
1.0
0.0
1997
1998
1999
2000
2001
2002
2003
2004
2005
FPL
PEF
TECO
GULF

Appendix B: Reliability Related Customer Complaints

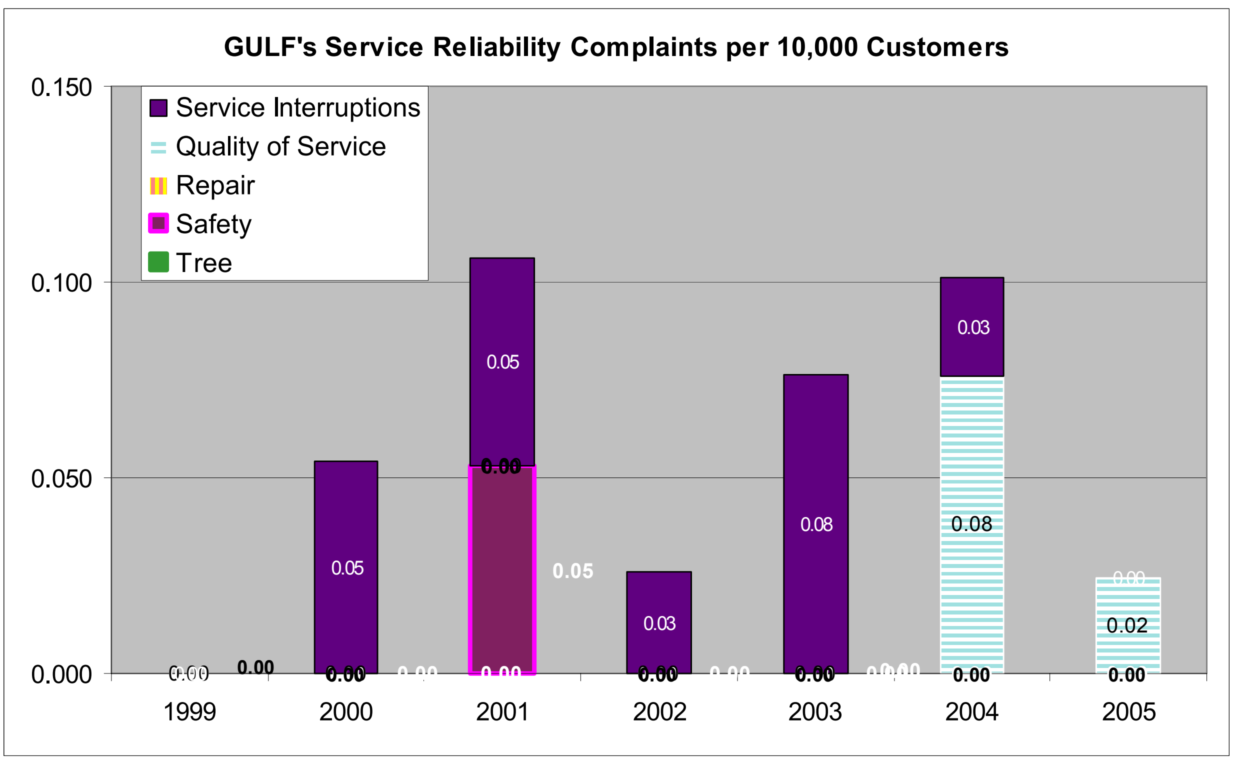
Note: The "Quality of Service" category was established in July of 2003, resulting in a shift of some complaints that previously would have been coded as another type of complaint.







TECO's Service Reliability Complaints per 10,000 Customers
1.00
0.75
0.50
0.25
0.00
Service Interruptions
Quality of Service
Repair
Safety
Tree
1999
2000
2001
2002
2003
2004
2005
0.17
0.07
0.19
0.52
0.08
0.49
0.22
0.62
0.05
0.06



GULF's Service Reliability Complaints per 10,000 Customers
0.150
0.100
0.050
0.000
Service Interruptions
Quality of Service
Repair
Safety
Tree
1999
2000
2001
2002
2003
2004
2005
0.05
0.05
0.03
0.08
0.03
0.08
0.02

Appendix C: Methods of Distribution Reliability Evaluation

Both quantitative and qualitative tools are used to review issues concerning the continuity of electric service experienced by customers. Service interruptions may be caused by events originating from the utility's generation, transmission, or distribution facilities. Because events originating from the distribution system account for the majority of customer interruptions, distribution reliability is the focus of this report. The utilities' annual distribution reliability reports contain a number of performance indicators that form the basis for staff's review. The following is a brief discussion of several commonly used indices provided in the annual reports and the additional tools used to review service reliability.

1. **Indicators of system average performance** – SAIDI, SAIFI, CAIDI are among the most commonly used indices for measuring sustained customer interruptions, or the loss of continuity of one minute or greater. MAIFIe measures momentary interruptions, or the loss of continuity of less than one minute. SAIFI, or System Average Interruption Frequency Index, indicates the average customer interruption frequency by calculating the average number of service interruptions per customer served. CAIDI, or Customer Average Interruption Duration Index, indicates the average interruption duration by calculating the average time to restore service to interrupted customers. SAIDI, or System Average Interruption Duration Index, is a composite indicator of outage frequency and duration. Mathematically, SAIDI is the product of SAIFI and CAIDI. Thus, a SAIDI of 100 may be achieved by a SAIFI of 1 and a CAIDI of 100, or by a SAIFI of 1.25 and a CAIDI of 80. MAIFIe, or Momentary Average Interruption Event Frequency Index, measures the average frequency of momentary interruptions by calculating the average number of momentary events per customer on primary feeders.

2. **Indicators of targeted improvement opportunities** – While the system-average indices are useful in tracking outage trends and system reliability goals, these indices have their limitations. For example, the system averages do not reveal whether the outages are evenly distributed among the customers. The averages may hide poor service received by a subset of customers. To help uncover such potential problems, CEMI and Three Percent Feeder Report are used. CEMI, or Customers Experiencing Multiple Interruptions, measures the percent of overall customers that have experienced more than a specific number of interruptions. CEMI5, for customers who have experienced more than five interruptions a year, is reported in the annual reliability reports of four utilities. Data from the Three Percent Feeder Report are used to assess the tendency for a subset of feeders to sustain a relatively high number of outages compared to other feeders on the system.

3. **Data related to named storms and other excluded events** – The 2004 and 2005 storm activities have elevated the public awareness of utility performance during named storms. Indeed, customer perception of a company's reliability may be more influenced by its performance during named storms than by its performance during other periods. The storm-related outage exclusion data provide an important view of service reliability. For the 2005 reporting period, statistics such as number of poles

replaced, SAIDI, and CAIDI for each of the named storms in 2005 are gathered in this review to gauge the storm's impact. As the utilities' data-gathering capability improves, staff expects future reports to include more detailed information, such as storm performance data that differentiates between overhead and underground systems. Review of the progress of the various hardening initiatives that utilities are required to implement is also expected in future reports. In addition to the storm-related data, other types of excluded outage data are also reviewed separately in recognition of the different aspects of service reliability represented by these data.

4. **Customer complaints and other activities** – Customer complaints processed by the Commission help provide insight into the service reliability concerns of individual customers. Staff's actions to help resolve these complaints include assessments of the utility system, outage data, and various distribution infrastructure maintenance and restoration programs; sometimes the solution involves customer visits and on-site evaluation. Often times, the solution improves the service to the community as well as to the complaining customer. Staff tracks the number of customer complaints filed with the Commission based on complaint types. For purposes of staff review, reliability related customer complaints are those complaints that require more than 72 hours to resolve and fall into the categories of service interruptions, repairs, safety, tree trimming, or quality of service. As shown in Appendix B, the service interruptions category, which includes both momentary and sustained interruptions, is the most frequently cited concern. In addition to the activities conducted on a regular basis, staff also conducts, as needed, special reviews such as audits of the data contained in the annual reports and management reviews of utility practices. The reliability data for the 2004 and 2005 reporting periods were not audited by Commission staff.

APPENDIX D

Initiative 1 – A Three-year Vegetation Management Cycle for Distribution Circuits

Order Requirements:
1. 3-year tree trim cycle for primary feeders (minimum). 2. 3-year cycle for laterals as well, if not cost prohibitive. 3. Utilities may propose alternatives to the requirements described below. Any alternatives must include a complete description of the alternative as well as the reason why the alternative is equivalent or better in terms of cost and avoiding future storm damages. 4. Timeline for implementation.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)*	Utility Alternative Incremental Cost Impact ($ million)*
FPL	1. Average 3-year trim cycle for feeders. 2. Average 6-year trim cycle for laterals, instead of 3-year cycle. 3. FPL's analysis of its alternative focused on the lateral trimming program. FPL believes that its analysis demonstrates that its proposed alternative is more cost effective. (The 3-year cycle would cost an average $30.3 million per year more than the 6-year cycle, while providing a potential incremental benefit of 55,000 fewer storm-related customer interruptions.) 4. Year One for implementation is 2007.	Year One – $88.9 Annual - $43.4	Year One – $15.5 Annual - $12.9
PEF	1. 3-year trim cycle for feeder backbones. 2. 5-year cycle for laterals. 3. PEF provided quantitative comparisons of the costs and benefits. The measuring tool will provide a basis for future evaluation. 4. Year One for implementation is 2007.	Year One - Annual – $12	Year One – Annual – $5.0
TECO	1. Feeder trim based on prioritization (all trimmed every 3 years). 2. Every circuit including open secondaries, cabled secondaries, and appropriate services is trimmed every 3 years. 3. TECO's program is a three-year trim-cycle program. 4. Year One for implementation is 2007, assuming 2-3 year transition allowed to stabilize costs, conduct training, etc.	Year One – N/R Annual $3.4	Not applicable.
GULF	1. 3-year trim cycle for feeders 2. 6-year maximum cycle for laterals. 3. GULF provided quantitative comparisons of the costs and benefits. The measuring tool will provide a basis for future evaluation. 4. Year One for implementation is 2007.	Year One – 4.2 Annual - $4.2	Year One – 1.5 Annual – 1.5
FPUC	1. All feeders on a 3-year trim cycle. 2. Laterals may be on a 3-year trim cycle or an alternative 5-year trim cycle in the NW service area. 3. The 5-year trim cycle is less expensive. 4. Year One for implementation is 2007.	Year One – N/R Annual - $.342	Year One – N/R Annual - $.228

* The incremental cost impact is based on comparisons with the existing trimming program forward. "N/R" No Response. Not Applicable: Not Applicable. "Year One" First Year of Implementation. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

APPENDIX D

Initiative 2 – Audit of Joint-Use Attachment Agreements

Order Requirements: 1. (a) Each investor-owned electric utility shall develop a plan for auditing joint-use agreements that includes pole strength assessments. (b) These audits shall include both poles owned by the electric utility and poles owned by other utilities to which the electric utility has attached its electrical equipment. 2. The location of each pole, the type and ownership of the facilities attached, and the age of the pole and the attachments to it should be identified. 3. Each investor-owned utility shall verify that such attachments have been made pursuant to a current joint-use agreement. 4. Stress calculations shall be made to ensure that each joint-use pole is not overloaded or approaching overloading for instances not already addressed by Order No. PSC-06-0144-PAA-EI. 5. Provide compliance cost estimate and cost estimate for alternative action if any. 6. Provide a timeline for implementation.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
FPL	1. (a) Plan includes performing pole strength assessment during eight-year wood pole inspection cycle. (b) Plan includes auditing all FPL owned and third-party poles during eight-year wood pole inspection cycle. 2. All required data will be collected during inspections and stored in the attachment information database. 3. Will verify attachments have been made pursuant to current joint-use agreement through a 5-year system wide pole attachment survey. 4. Stress calculations will be performed during 8-year wood pole inspection cycle. 5. See columns to the right. 6. Plan will be initiated January 2007 with completion cycles of eight-years.	Annual - $1.2 – 1.5	Not Applicable
PEF	1. (a) Plan includes performing pole strength assessment during eight-year wood pole inspection cycle. (b) Plan includes auditing all PEF owned and third-party poles during eight-year wood pole inspection cycle. 2. All required data will be collected on <u>select</u> poles and stored in electronic format. 3. Will verify attachments have been made pursuant to a current joint-use agreement during eight-year wood pole inspection cycle. 4. Stress calculations will be performed on <u>select</u> poles during eight-year wood pole inspection cycle. 5. See columns to the right. 6. Plan initiated 2006 with completion cycles of 8-years.	Annual - $.080	Not Applicable
TECO	1. (a) Plan includes performing pole strength assessment during 8-year wood pole inspection cycle. (b) Plan includes auditing all TECO owned poles and third-party poles per joint-use contract agreements on an eight-year cycle. 2. All required data will be collected during the eight-year wood pole inspection cycle and stored in GIS database. 3. Will verify attachments have been made pursuant to a current joint-use agreement during eight-year wood pole inspection cycle. 4. Stress calculations will be performed during eight-year wood pole inspection cycle.	Annual - $5	Not Applicable

APPENDIX D

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
	5. See columns to the right. 6. Plan will be initiated January 2007 with completion cycles of eight years.		
GULF	1. (a) Plan proposes to do pole strength assessment on 5% random sample of GULF owned poles that are 20 years old or more and with 3 or more attachments. (b) Plan includes auditing all GULF owned poles and third-party poles per joint-use contract agreements on a 10-year cycle. 2. All required data will be collected and stored during 10-year inspection cycle. 3. Will verify attachments have been made pursuant to current joint-use agreement through a 10-year cycle. 4. Stress assessment will be performed on 5% random sample of GULF owned poles that are 20 years old or more and with 3 or more attachments. 5. See columns to the right. 6. Plan will be initiated January 2007 with completion cycles of 10 years.	Annual - $5.375	Not Applicable
FPUC	1. (a) Plan includes performing pole strength assessment during eight-year wood pole inspection cycle. (b) Plan includes auditing all FPUC owned and third-party poles during eight-year wood pole inspection cycle. 2. All required data will be collected during inspections and stored in a database. 3. Will verify attachments have been made pursuant to a current joint-use agreement during eight-year wood pole inspection cycle. 4. Stress calculations will be performed during eight-year wood pole inspection cycle. 5. See columns to the right 6. Plan will be initiated January 2007 with completion cycles of eight years.	Annual - $.020	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. “Annual” refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

APPENDIX D

Initiative 3 – Six-year Transmission Inspection Program

Order Requirements:

1. Develop a plan to fully inspect all transmission towers and other transmission supporting equipment (such as insulators, guying, grounding, splices, cross-braces, bolts etc.).
2. Develop a plan to fully inspect all substations (including relay, capacitor, and switching stations).
3. Provide a timeline for implementation.
4. Provide compliance cost estimate and cost estimate for alternative actions, if any.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
FPL	1. Wood pole inspection activities (PSC-06-0144-PAA-EI Docket No. 060078-EI). Circuits with structures containing wood cross-arm structures inspected at least every 4 years. Steel and/or concrete structures (no wood) inspection activities 10% sample during every 4-year program will be augmented to achieve equivalent of a non-sample six-year inspection cycle. Inspection of insulators, wires, etc., are included in the augmented efforts. 2. Substations fully inspected quarterly. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $12.9 million, annually.	Annual - $2.3	Not Applicable
PEF	1. Wood pole inspection activities (PSC-06-0144-PAA-EI Docket No. 060078-EI). Structures on a 5-year inspection cycle. All other portions of the system: inspected on a three-year cycle. 2. Monthly visual substation inspection. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $0.	Annual - $ 0	Not Applicable
TECO	1. Wood pole inspection activities (PSC-06-0144-PAA-EI Docket No. 060078-EI). Structures on a 6 year cycle, All other portions of the system: inspected annually. 2. Substations fully inspected at least annually. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $0.	Annual - $2.97	Not Applicable
GULF	1. Wood pole inspection activities (PSC-06-0144-PAA-EI Docket No. 060078-EI). All other portions of the system: GULF does not hold itself to a rigid number of annual inspections. Period of 12 years will show that on average a six-year cycle is achieved. 2. Substations at least annually. Structures inside new substations built to withstand wind speed in excess of 150mph. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $0.	Annual - $ 0	Not Applicable
FPUC	1. Will develop procedures for climbing inspections of owned 69 and 138 kV structures. Coordination/process for customer-owned 69 V line will be developed. 2. No plan provided for substations. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $18,000, annually.	Annual - $.018	Not Applicable

Incremental cost impact is calculated using 2005 as a base year.
"Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

APPENDIX D

Initiative 4 – Hardening of Existing Transmission Structures

Order Requirements: 1. Develop a plan to upgrade and replace existing transmission structures. Provide scope of activity, limiting factors, and criteria for selecting structure to upgrade and replace. 2. Provide a timeline for implementation. 3. Provide compliance cost estimate and cost estimate for alternative actions, if any.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Company Alternative Incremental Cost Impact ($ million) *
FPL	1. Incremental upgrades during relocations and other maintenance. Upgrade un-guyed single wood pole structures. Ceramic post line insulator replacements. 2. Plan completed in 10-15 years. 3. Estimated incremental costs relative to 2005 is between $3.3 and $6 million, annually.	One Time - $0 Annual - $3.3-6	Not Applicable
PEF	1. Incremental upgrades during relocations and other maintenance. 2. Plan completed in 10 or more years. 3. Estimated incremental costs relative to 2005 are $0.	One Time - $0 Annual - $2.8	Not Applicable
TECO	1. Incremental phase out of wood transmission structures during all new construction, relocations, and other maintenance. 2. Plan is on-going with no completion date. 3. Estimated incremental costs relative to 2005 are a one time cost of $2.5 million.	One Time - $2.5 Annual - $0	Not Applicable
GULF	1. Storm guy H-Frames. Replace wood cross-arms with steel cross-arms and other activities. 2. Plan completed in 10-15 years. 3. Estimated incremental costs relative to 2005 are $0.6 million.	One Time - $0.2 Annual - $0.6	Not Applicable
FPUC	1. Replacement of 180 wood poles on 69 KV line with concrete as necessary and when economically practical. 2. Plan is on-going with no completion date. 3. Estimated total cost is $4.5 million.	One Time - $4.5 Annual - $0	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. “Annual” refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

APPENDIX D

Initiative 5 - A Transmission and Distribution Geographic Information System

Order Requirements: Develop a program that collects data 1. To conduct forensic reviews; 2. To assess the performance of underground systems relative to overhead systems; 3. To determine whether appropriate maintenance has been performed; and 4. To evaluate storm hardening options. The utilities have the flexibility to propose a methodology that is efficient and cost effective. The Utilities should provide a timeline for implementation

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
FPL	Transmission: FPL currently has its transmission lines and structures identified by geographic area and sub-area, and GPS location. 1. FPL's proposed alternative does not include forensic reviews. 2. FPL's proposed alternative does not include underground versus overhead. 3. FPL's proposed alternative does not include determination of appropriate maintenance. 4. FPL's proposed alternative does not include evaluation of storm hardening options. 5. None. Distribution: Combine existing analytical systems to have all facilities in a GIS platform, being able to identify performance of circuits and certain devices, providing a good forensic analysis of FPL's facilities after a hurricane, identifying maintenance and providing a separate view of hardened facilities. 1. Combine existing analytical systems to have all facilities in a GIS platform, being able to identify performance of circuits and certain devices, providing a good forensic analysis of FPL's facilities after a hurricane, identifying maintenance and providing a separate view of hardened facilities. 2. FPL's proposed alternative does not include underground versus overhead. 3. FPL's proposed alternative does not include determination of appropriate maintenance. 4. FPL's proposed alternative does not include evaluation of storm hardening options. 5. Three years.	One Time - $14.55 Annual - $3.13	One Time – $6.3 Annual - $.5
PEF	Transmission: PEF plans to "populate" the system (present GIS system) with maintenance data that will be captured in PEF's Transmission Line Inspection Plan. 1. PEF's plan does not include forensic reviews. 2. PEF's plan does not include underground versus overhead performance assessment. 3. PEF's plan does not include determination of appropriate maintenance. 4. PEF's plan does not include evaluation of storm hardening options. 5. Six years. Distribution: PEF plans to create an environment that contains all the elements referenced by the order,	One Time - $8.8 Annual - $.30	Not Applicable

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Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
	change its current GIS system from location driven to asset driven, thereby being able to collect data from many sources which would provide it with the ability to look for trends in performance of individual assets. 1. PEF's plan does not include forensic reviews 2. PEF's plan does not include underground versus overhead. 3. PEF's plan does not include determination of appropriate maintenance. 4. PEF's plan does not include evaluation of storm hardening options 5. 6 years		
TECO	TECO is in the process of implementing a new GIS system. The field assets that will be incorporated in the GIS will include all distribution, transmission, substation, and lighting facilities for TECO's entire system. GIS, in conjunction with current OMS, will provide information on location and system performance. 1. TECO's plan includes forensic reviews on a statistically sampled basis. 2. TECO's plan includes forensic reviews with regard to types of materials and construction, and location 3. TECO's plan does not include determination of appropriate maintenance. 4. TECO's plan includes assessment of future preventive measures where possible. 5. Not Applicable.	One time - $.4 Annual – Not Applicable.	Not Applicable
GULF	GULF describes its GIS system, but does not mention location or performance data. 1. GULF's plan includes forensic reviews 2. GULF's plan includes underground versus overhead. 3. GULF's plan includes determination of appropriate maintenance. 4. GULF's plan includes evaluation of storm hardening options 5. 6 Years	One Time - $0 Annual - $.075	Not Applicable
FPUC	1-4. NW FL Division currently has in place a GIS system capable of collecting all of the necessary information. Additional procedures will be developed to ensure that NW FL can use the data as ordered. 1-4. NE Florida Division does not have this capability but will upgrade its present system 5. Not Applicable.	One Time - $.19 Annual - $.0	Not Applicable

* The incremental cost impact is based on comparisons with the existing trimming program going forward. "Year One" refers to First Year of Implementation. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

APPENDIX D

Initiative 6 – Post-Storm Data Collection and Forensic Analysis

Order Requirements: 1. Develop a program that collects post-storm information for performing forensic analyses. 2. Provide a timeline for implementation. The utilities have the flexibility to propose a methodology that is efficient and cost effective.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
FPL	1. <u>Distribution</u>: Divide a sample of damaged poles among forensics teams; observations will be made on all damaged samples. Capture information such as location, attachments, and area wind speed. <u>Transmission</u>: For the 2004 and 2005 storm season, FPL used the storm management system called Orion Storm. The system captures 100% of the damaged impacted lines. Forty-one percent of the lines imported included detailed data collected with the Orion Storm Program. Fifty-nine percent of the lines impacted did not involve damaged facilities. FPL proposes to collect data for these transmission facilities to meet the Commission initiative. 2. <u>Distribution</u>: Available for 2006 storm season. <u>Transmission</u>: Currently activated program.	One Time - $0 Annual - $.050-.10	Not Applicable
PEF	1. <u>Distribution</u>: PEF has implemented the Forensic Assessment process for the upcoming 2006 storm season. <u>Transmission</u>: PEF will hire a contractor. The contractor will collect detailed post storm data necessary to perform storm damage and forensic analysis. 2. Available for 2006 storm season.	One Time - $0 Annual $.9/ per storm	Not Applicable
TECO	1. <u>Distribution & Transmission:</u> TECO plans to implement a formal process to randomly sample system damage following a major weather event in a statistically significant manner. This information will be used to perform forensic analysis in an attempt to categorize the root cause of equipment failure. 2. One Year.	One time - $.2 Annual - $.1 per storm	Not Applicable
GULF	1. <u>Distribution & Transmission:</u> Concurrent with storm restoration, crews of contractors will survey a sample of the lines affected by the storm. Inland and coastal areas will be surveyed. 2. No Response.	One time - $0 Annual - $.125/per storm	Not Applicable
FPUC	1. <u>Distribution & Transmission</u>: FPUC will develop a procedure to better track specific hurricane outages, identify outage causes, and count the numbers of customers affected. 2. No Response.	One Time - $.017 Annual - $.010/per storm	Not Applicable

* The incremental cost impact is based on comparisons with the existing trimming program going forward. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

APPENDIX D

Initiative 7 – Collection of Detailed Outage Data Differentiating between the Reliability Performance of Overhead and Underground Systems

Order Requirements: 1. Collect specific storm performance data that differentiate between overhead and underground systems, to determine the percentage of storm caused outages that occur on overhead and underground systems, and to assess the performance and failure mode of competing technologies such as direct bury cable versus cable-in-conduit, concrete poles versus wooden poles, and location factors such as front-lot versus back-lot, and pad-mounted versus vault. 2. Provide a timeline for implementation. The utilities have the flexibility to propose a methodology that is efficient and cost effective.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)	Company Alternative Incremental Cost Impact ($ million)
FPL	1. FPL proposes analyzing storm specific *samples* of locations (feeders, laterals, etc.) based on identifying GIS information established in compliance with initiatives #5 and #6. FPL does not plan to hold up storm restoration in order to ensure complete enumerations or adequate sample sizes for making valid inferences. FPL stresses that this practice would be particularly true of smaller storms, from which recovery is typically more rapid. Feeders tend to be hybrids with regard to underground and overhead. Forensics teams will be augmented to assess the damages to the various locations. Laterals tend to be either one or the other, so assessments with regard to overhead or underground will be available by knowing a lateral's location. 2. No Response.	One Time - $0 Annual - $.05-.1/per storm	Not Applicable
PEF	1. The implementation of the new GIS system would enhance PEF's ability to collect data relevant to assess performance, and PEF would use this data to analyze and compare the performance of its overhead and underground systems. 2. No Response.	Response One Time – No Response Annual – No Response	Not Applicable
TECO	1 TECO currently collects outage data. TECO will implement to fully comply with the Commission initiative for the collection of detailed outage data differentiating between the reliability performance of overhead and underground systems. 2. One Year.	One Time - $.5 Annual - $0	Not Applicable
GULF	1 GULF will record numbers of overhead and underground customers and calculate SAIDI and SAIFI for each outage. As outages occur, GULF will also collect data by type of buried cable and type of pole. 2. Three-fourths Year	One time - $0 Annual – minimal	Not Applicable
FPUC	1. FPUC is currently able to carry out this initiative. 2. Available now.	One Time - $0 Annual - $0	Not Applicable

* The incremental cost impact is based on comparisons with the existing trimming program going forward. "One Time" refers to first year set-up costs. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

APPENDIX D

Initiative 8 – Increased Coordination with Local Governments

Order Requirements: 1. Each utility should actively work with local communities year-round to identify and address issues of common concern, including the period following a severe storm like a hurricane and also ongoing, multihazard infrastructure issues such as flood zones, areas prone to wind damage, development trends in land use and coastal development, joint use of public right-of-way, undergrounding facilities, tree trimming, and long range planning and coordination. 2. Provide a timeline for implementation. 3. Incremental plan costs.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)*	Company Alternative Incremental Cost Impact ($ million)*
FPL	1. The FPL Plan focuses initially on storm preparation, coordination and communication with External Affairs representatives working with county planners and post-storm communications. FPL plans to implement: ▪ On-going planning programs with External Affairs representatives working with local government officials. ▪ A special e-mail program oriented to government officials and special audiences. ▪ A new government update website. ▪ A program called "community trouble reporting." ▪ Community outreach teams to brief local government and customer groups. 2. No specific timeline for implementation of the entire plan is provided except for a general reference to May 2006 marking the start date for some programs. 3. Incremental costs are only provided for the training ($25k) and Wire Down/Priority 1 ($12k) and Communications ($100k). No methodology for cost estimates are provided.	One Time - $.1 Annual - $.012	Not Applicable
PEF	1. The PEF Plan provides an internal team composed of community relations, regulatory affairs and account management to coordinate company planning with governmental activities. The activities include assigning specific staff to work with individual communities to identify opportunities throughout the year for improved preparedness, developing enhanced organization and planning, providing support and information for storm preparation and restoration, conducting an annual storm drill, and conducting on-going activities such as planning workshops and town-hall type meetings at both state and county levels. 2. No specific timeline for implementation of the entire plan is provided except for a general reference 2006 marking the start date for the programs. 3. Incremental costs for the plan are not provided. No methodology for estimating cost are provided.	One Time – No Response Annual – No Response	Not Applicable
TECO	1. TECO's Plan calls for building on past community involvement by including local government, fire, police, and water officials in storm preparation workshops, including local government in local Emergency Operations Centers, increasing vegetation management including government and consumer education, undergrounding planning and education, and damage reporting prior, during, and after storms. 2. No specific timeline for implementation of the entire plan is provided except for a general reference to some of the programs having already started in 2006.	One time - $0 Annual - $.075	Not Applicable

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Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)*	Company Alternative Incremental Cost Impact ($ million)*
	3. Only a general incremental cost for the overall plan is provided ($75,000). No methodology for estimating costs is provided.		
GULF	1. The GULF Plan builds on existing programs of year round activities like workshops with community leaders, pre-hurricane planning with participation in all local government hurricane preparedness drills, exercises, information fairs by line clearing specialists and post hurricane programs to include timely news announcements to government officials, single point-of-contact personnel and Emergency Operations Center. 2. GULF's Programs are currently ongoing. 3. No incremental costs are provided since the programs are considered already ongoing. No methodology for estimating costs is provided.	One Time - $0 Annual - $0	Not Applicable
FPUC	1. The FPUC Plan calls for interacting with local governments in each of the separate divisions of the Company, having personnel at local Emergency Operations Centers after each storm, and engaging in discussions with local government on both undergrounding and tree trimming issues as they arise. 2. No specific timeline for implementation of the entire plan since the program is simply a continuation of the activities that were carried out in 2005. 3 No incremental cost were listed with the exception of an estimated cost of $7,500 per event that FPUC staff attended. No methodology for estimating costs were provided.	One Time - $0 Annual - $0	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. "One Time" refers to first year set-up costs. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

APPENDIX D

Initiative 9 – Collaborative Research

Order Requirements: 1. IOUs must establish a plan that increases collaborative research. 2. IOUs must identify collaborative research objective. 3. IOUs must develop collaborative plans that promote cost sharing. 4. IOUs must solicit municipal, coops, educational and research institutions. 5. IOUs must establish timeline for implementation. 6. IOUs must identify their incremental costs necessary to fund the organization and perform the research.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Company Alternative Incremental Cost Impact ($ million) *
FPL	1. FPL indicates support for the creation of a non-profit, member supported organization that coordinates all research efforts in the area of storm effects on utility infrastructures. 2. FPL did not enumerate research objectives. FPL did not identify any specific research projects. 3. FPL proposed a non-profit, member supported organization for researching storm effects on utility infrastructure with the Public Utility Research Center (PURC) as the host. FPL suggested a single coordinator of research efforts from each member utility and proposes an organization which would pursue two types of research: membership funded research voted on by the majority of members and individually funded research (not voted or funded by other utilities). 4. FPL states the IOUs will solicit participation from the municipal and rural electric cooperative utilities in addition to available educational and research organizations. 5. No timeline for implementation was provided. 6. For cost requirements, see column to the right.	One Time - $0 Annual - $05-$.10	Not Applicable
PEF	Same as FPL.	One Time - TBD Annual – TBD	Not Applicable
TECO	Same as FPL.	One Time - TBD Annual – TBD	Not Applicable
GULF	Same as FPL. In addition, GULF plans on continuing to participate as appropriate within Southern Company and its own R&D efforts. GULF may also engage in R&D through a local university in Northwest Florida.	One Time - TBD Annual – TBD	Not Applicable
FPUC	Same as FPL. Commitment to fund research regarding hurricane winds and storm surge. Requires reasonable allocation of costs based on customers, net load, etc.	One Time - $0 Annual - $.025	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. "One Time" refers to first year set-up costs. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation. "TBD" means To Be Determined.

APPENDIX D

Initiative 10 – A Natural Disaster Preparedness and Recovery Program

Develop a formal Natural Disaster Preparedness and Recovery Plan that outlines the utility's disaster recovery procedures if the utility does not already have one.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)	Company Alternative Incremental Cost Impact ($ million)
FPL	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable
PEF	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable
TECO	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable
GULF	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable
FPUC	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable

APPENDIX E

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Co'rd. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
JEA	387,685	3-Yr All	Audit in 2002. No stress calc	4-Yr	No new wood; No plan existing	Migrating to electronic system +1-yr	Done	Collected - Not reported	Yes	See MOU	Yes
Orlando Utilities Commission	194,081	4-Yr Feeders, N/A Lat	Audit Plan No stress calc	6-Yr	Phase out wood trans poles	Electronic system for 100% assets	In future plans	Collected - Not reported	Yes	See MOU	Yes
Lakeland Electric	120,000	5-Yr All	Audit in 2005. Stress calc as needed	1-Yr	Phase out wood trans poles	Electronic system of 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Tallahassee, City of	109,000	1.5 -Yr All	Audit Fall 2006. Plan to stress calc	5-Yr; 8-yr for wood poles	Phase out wood trans poles	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Gainesville Regional Utilities	87,700	3-Yr All	Audit only. No stress calc	1-Yr	No plans to replace wood poles	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Kissimmee Utility Authority	62,000	4-Yr All	Audit not discussed. Plan to stress calc	5-Yr; 8-yr for wood poles	Phase out wood trans poles	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Ocala Electric Utility	48,300	4-Yr All	5-Yr Audit. Stress calc	6-Yr	No plan to replace wood poles	Electronic from Substation to Service	Done	Collected - Plan to report	Yes	See MOU	Yes

APPENDIX E

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Co'rd. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Vero Beach, City of	32,500	2-3 Yr All	5-Yr Audit cycle. Stress calc for new poles	1-Yr (River crossing @10 yrs)	No plan to replace wood poles	Electronic system for 100% assets	May install system	Collected - Not reported	Yes	See MOU	Yes
Beaches Energy Services	32,000	3-Yr All	Plan to Audit. No stress calc	1-Yr Visual 69 Kv, Plan aerial 138 Kv	None	Migrating to electronic + ? yr	Done	Collected - Not reported	Yes	See MOU	Yes
Lake Worth Utilities Dept.	27,400	2-Yr All	Plan to Audit 2006. No stress calc	1-Yr	None	Electronic system for 100% assets	Partial implemen tation	Plan to collect - Not reported	Yes	See MOU	Yes
Keys Energy Services	27,000	2-Yr All	No Audit. No stress calc	2 Yr Aerial, 3-4 Yr Foundations	None	Electronic system for 100% assets	Done	Upgrade in progress	Yes	See MOU	Yes
Fort Pierce Utilities Authority	26,500	3-Yr All	Audit 2006. No stress calc	1-Yr Trans, 3-Yr Line Hardware	Class 2 wood poles, Reviewing	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
New Smyrna Beach	24,000	Ongoing All	Audit includes stress calc	4-5-Yr	Phase out wood trans poles	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Leesburg, City of	21,500	4-Yr All	5-Yr Audit cycle. Plan stress calc	Not Applicable	None	Electronic system for 100% assets	Plan more detail	Collected - Reported	Yes	See MOU	Yes

APPENDIX E

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Co'rd. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Homestead, City of	19,500	Less than 3-Yr for all	5-Yr Audit cycle with stress calc	6-Yr, 2-Yr Thermo	None	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Winter Park, City of	14,000	2-3-Yrs	Plan to Audit. No stress calc	Not Applicable	Not Applicable	Migrating to electronic system + 1 yr	Done	Collected - Plan to report	Yes	See MOU	Yes
Bartow, City of	10,500	4-Yr All	No Audit cycle. Stress calc for big cables	Not Applicable	Not Applicable	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Mount Dora, City of	5,800	1-Yr All	Audits regularly. No stress calc	Not Applicable	Not Applicable	Paper system for 100% of assets. Plan for GIS	Done	Collected - Not reported	No men-tion of EOC	See MOU	Yes
Quincy, City of	4,580	1-Yr All	No Audit cycle. No stress calc	6-Yr, 2-Yr Thermo	None	Paper system for 100% assets	Done	Not currently	Yes	See MOU	In Process
Clewiston Utilities, City of	4,135	1-Yr Feed Removal by Request Dist	5-Yr Audit cycle. No stress calc	2-Yr	None	Migrating to electronic system +7-yrs	Partial implemen t	Collected - Not reported	Yes	See MOU	Plans to
Alachua, City of	3,600	3-Yr All	3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Migrating to electronic system +2 yr	Done	Collected - Not reported	Yes	See MOU	In Process

APPENDIX E

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Co'rd. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Green Cove Springs, City of	3,600	1-Yr All	No Audit cycle. No stress calc	Not Applicable	None	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Starke, City of	3,000	1-Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Wauchula, City of	2,773	3-Yr	3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Migrating to electronic system + ? yr	Done	Collected - Not reported	Yes	See MOU	Plans to
Fort Meade, City of	2,647	3-4 Yr All	2-3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets. Plan GIS	Done	Collected - Not reported	Yes	See MOU	In Process
Williston, City of	1,390	1-Yr All	3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	In Process
Blountstown, City of	1,333	3-Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Havana, Town of	1,310	3-Yr All	2-3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets. Plan GIS	Done	Collected - Not reported	Yes	See MOU	Yes

APPENDIX E

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**I0**
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Co'rd. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Newberry, City of	1,300	1-1.5 Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets Plan GIS	Done	Collected - Not reported	Yes	See MOU	Plans to
Chattahoochee, City of	1,298	1-Yr All	3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Plans to
Reedy Creek Improvement District	1,213	Not applicable. 99% UG.	No overhead attachments.	Monthly	None	Electronic system for 100% assets	Done	99% UG	Yes	See MOU	Yes
Bushnell, City of	1,132	1-Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Yes
Moore Haven, City of	842	1-1.5 Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	Plans to
St. Cloud, City of		See Orlando Utilities Commission.									
Done = Post-storm damage review process in place in the nature of lessons learned.											

APPENDIX F

Summary of Rural Electric Cooperative Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	2	3	4	5	6	7	8	9	10
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Withlacoochee River Electric Coop., Inc.	177,972	4-5-Yr cycle all	5-Yr Audit cycle. Yes.	1-Yr cycle	Replace wood poles 3-5 yrs	Electronic system for 100% assets	Done	Collected and reported.	Yes	See MOU	Yes
Lee County Electric Coop., Inc.	168,749	3-6-Yr cycle all	Audit 2001. No stress Calc	1-2-Yr cycle	No new wood poles. Phase-out wood poles	Electronic system for 100% assets	Done	No collection – Not Reported	Yes	No	Yes
Clay Electric Coop., Inc.	164,000	3-5-Yr cycles based on city/rural criteria Avg. 3.9 all	Audit 2008 Some stress calc	6-Yr cycle 4X-Yr Thermo	No plan to replace wood poles	Non-GPS electronic system	Done	Collected – Plan to report	Yes	See MOU	Yes
Sumter Electric Coop., Inc.	152,000	3-Yr cycle all, not adequate; New Plan	Audit for un-notified attachments. Stress calc	5-Yr cycle 1.5-Yr Thermo	No new wood poles. Phase-out some wooden structures	Electronic system for 100% assets	Done	Collected-Not Reported – No value.	Yes	See MOU	Yes
Talquin Electric Coop., Inc.	52,838	Target 3-Yr cycle all; achieved 3.7- Yr	5-Yr Audit cycle. No stress calc	8-Yr cycle	Phase out wood poles	Considering whether need exists	Done	Not Collected - Not reported.	Yes	See MOU	Yes
Choctawhatchee Electric Coop., Inc.	36,987	5-Yr cycle all	3-Yr Audit cycle. Stress calc	Not Applicable	Not Applicable	Electronic system for 100% assets	Done	Collected - Not reported.	Yes	See MOU	Yes
Peace River Electric Coop., Inc.	34,500	3-Yr cycle all; not Adequate	No Audit. No stress calc	6-Yr cycle	No new wood poles. Phase out wood poles	Electronic system for 100% assets	Done	Plan to Collect - Plan to report	Yes	See MOU	Yes

APPENDIX F

Summary of Rural Electric Cooperative Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	2	3	4	5	6	7	8	9	10
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Central Florida Electric Coop., Inc.	31,702	4-Yr cycle all	5-Yr Audit cycle. No stress calc	Targets 1-Yr Cycle	No plan to replace wood poles	Paper system	Done	Few UG facilities.	Yes	See MOU	Yes
Florida Keys Electric Coop. Ass., Inc.	31,000	3-Yr cycle all	3-Yr Audit cycle. Yes.	1-Yr cycle	None	Migrating to electronic system	Done	Collected - Not reported.	Yes	See MOU	Yes
West Florida Electric Coop. Ass., Inc.	27,000	4.5-Yr cycle all	5-Yr Audit cycle. No stress calc	Not Applicable	None	Electronic system for 100% assets	Done	Collected - Not reported.	Yes	See MOU	Yes
Suwannee Valley Electric Coop., Inc.	24,000	4 Yr cycle all	Audit 2007. No stress calc	8-Yr, Own 5	Not Applicable	Electronic system for 100% assets	Done	Collected - Not reported.	Yes	See MOU	Yes
GULF Coast Electric Coop., Inc.	20,098	5-Yr cycle all	8-Yr Audit cycle. No stress calc	Not Applicable	None at this time.	Electronic system for 100% assets	Done	Collected - Not reported.	Yes	See MOU	Yes
Tri-County Electric Coop., Inc.	17,200	5-Yr cycle all	Audits are current. No stress calc	1-Yr cycle	No plan to replace wood poles.	Some electric some Paper	Done	Collected - Not reported 95% OH.	Yes	See MOU	Yes
Glades Electric Coop., Inc.	16,063	3-Yr cycle all	2-Yr Audit cycle. No stress calc	1-Yr cycle	No plan to replace wood poles. Harding	Migrating to electronic system 2007	Done	Collected - Not reported.	Yes	See MOU	Yes
Escambia River Electric Coop., Inc.	10,100	5-Yr cycle all	Plan Audit. No stress calc	Not Applicable	None at this time	Migrating to electronic system	Done	Collected - Reported	Yes	See MOU	Yes
Okefenoke Rural Electric Membership Corporation	8,883	3-Yr cycle all	Start 5-Yr Audit cycle. Some stress calc	Not Applicable	None at this time	Electronic system for 100% assets	Done	Collected – Not Reported.	Yes	See MOU	Yes

APPENDIX F

Summary of Rural Electric Cooperative Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Alabama Electric Coop., Inc.*	No Retail Customers	Not Applicable	No Audit No stress calc	4-Yr cycle	No plan to replace wood poles	Migrating to electronic system	Done	No UG facilities.	Yes	See MOU	Yes
Seminole Electric Coop., Inc.*	No Retail Customers	Not Applicable	No Audit No stress calc	Unknown	No Plan – Not Cost Effective	No GIS system planned	Done. Limited history.	No UG facilities.	Yes	See MOU	Yes
1* Alabama Electric is a generating and transmission cooperative providing wholesale service in Florida to 4 rural electric cooperative utilities. 2* Seminole Electric is a generating and transmission cooperative providing wholesale service in Florida to rural electric cooperative utilities.											
Done = Post-storm damage review process in place in the nature of lessons learned.											