Review of Florida's
Investor-Owned Electric Utilities' Service Reliability
in 2007

Florida Public Service Commission
Division of Economic Regulation
December 2008

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Terms and Acronyms

CAIDI	Customer Average Interruption Duration Index
CI	Customer Interruption
CME	Customer Momentary Events
CMI	Customer Minutes of Interruption
N	Measures the primary causes of outage events and identifies feeders with the most outages
L-Bar	Average of customer service outage events lasting a minute or longer
EOC	Florida's Emergency Operations Center
F.A.C.	Florida Administrative Code
FPL	Florida Power & Light Company
FPUC	Florida Public Utilities Company
GIS	Geographic information system
Gulf	Gulf Power Company
IOU	The five investor-owned electric utilities: FPL, PEF, TECO, Gulf, and FPUC
CEMI5	Percent of customers that experienced more than five service interruptions
MAIFIe	Momentary Average Interruption Event Frequency Index
PEF	Progress Energy Florida, Inc.
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TECO	Tampa Electric Company

Reliability Metrics Used in This Review

1. *Customer Minutes of Interruption* (CMI) is the number of minutes that a customer's electric service was interrupted for one minute or longer.

2. *Customer Interruption* (CI) is the number of customer service interruptions which lasted one minute or longer.

3. *Customer Momentary Events* (CME) is the number of customer momentary service interruptions which lasted less than one minute measured at the primary circuit breaker in the substation.

4. *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 (CAIDI = CMI ÷ CI, also CAIDI = SAIDI ÷ SAIFI).

5. *System Average Interruption Frequency Index* (SAIFI) is an indicator of average service interruption frequency experienced by customers on a system. SAIFI is calculated by dividing the number of service interruptions by the number of customers served (SAIFI = CI ÷ C, also SAIFI = SAIDI ÷ CAIDI).

6. *System Average Interruption Duration Index* (SAIDI) is a composite indicator of outage frequency and duration and is calculated by dividing the customer minutes of interruption by the number of customers served on a system (SAIDI = CMI ÷ C, also SAIDI = SAIFI x CAIDI).

7. *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 (MAIFIe = CME ÷ C).

8. *Customers Experiencing More Than Five Interruptions* (CEMI5) measures the percent of customers that have experienced more than five service interruptions. CEMI5 is a customer count often shown as a percentage of total customers.

9. *Number of Outage Events* (N) measures the primary causes of outage events and identifies feeders with the most outage events.

10. *Average Duration of Outage Events* (L-Bar) is the simple average of customer service outage events lasting a minute or longer.

Executive Summary

This report addresses both Florida's investor-owned electric utilities (IOUs) storm hardening initiatives and assesses trends in the reliability of service provided by the IOUs. Storm hardening activities are meant to protect Florida's citizens against prolonged service outages during extreme weather events. Throughout this review, emphasis is placed on observations that suggest declines in service reliability and thus reveal areas where additional scrutiny or remedial action may be required by a company.

Status of Storm Hardening Activities

On April 25, 2006, the Commission issued Order No. PSC-06-0351-PAA-EI, requiring the IOUs to file plans for ten ongoing storm preparedness initiatives.

The ten initiatives are:

(1) A three-year vegetation management cycle for distribution circuits
(2) An audit of joint-use attachment agreements
(3) A six-year transmission structure inspection program
(4) Hardening of existing transmission structures
(5) A transmission and distribution geographic information system
(6) Post-storm data collection and forensic analysis
(7) Collection of detailed outage data differentiating between the reliability performance of overhead and underground systems
(8) Increased utility coordination with local governments
(9) Collaborative research on effects of hurricane winds and storm surge
(10) A natural disaster preparedness and recovery program

While not all-inclusive, some 2007 highlights of Florida's IOUs' storm preparedness activities include:

- FPL reported inspecting 96% of its wood poles required to meet the 2007 contribution to its 8-year inspection plan. FPL clears vegetation from its feeder circuits on a 3-year trim cycle. FPL reported clearing 99% of feeder circuits for the 2007 contribution of the three-year plan. FPL clears vegetation from its lateral circuits on a 6-year trim cycle. FPL reported clearing 59% of lateral circuits for the 2007 contribution to its 6-year plan.

  FPL's coordination with local governments in 2007 included holding various meetings and workshops with local governments and county emergency operation centers (EOCs). The focus of these meetings was to discuss FPL storm hardening activities and to examine better ways to collaborate with local government during emergency situations.

- PEF reported inspecting 104% of its wood poles required to meet the 2007 contribution to its 8-year inspection plan. PEF clears vegetation from its feeder circuits on a 3-year trim cycle. PEF reported clearing 167% of feeder circuits for the 2007 contribution of the 3-year plan. PEF clears vegetation from its lateral circuits on a 5-year trim cycle. PEF reported clearing 78% of lateral circuits for the 2007 contribution to its 5-year plan.

  PEF's coordination with local governments in 2007 included holding meetings and expositions with local government, county EOCs, and first responders. These events included discussions to coordinate emergency planning activities, training activities, and community education seminars.

- TECO reported inspecting 139% of its wood poles required to meet the 2007 contribution to its 8-year inspection plan. TECO clears vegetation from its feeder circuits on a 3-year trim cycle. TECO reported clearing 63% of feeder circuits for the 2007 contribution of the 3-year plan. TECO clears vegetation from its lateral circuits on a 3-year trim cycle. TECO reported clearing 64% of lateral circuits for the 2007 contribution to its 3-year plan.

  TECO's coordination with local governments in 2007 included discussions of pre-storm preparedness and hazard mitigation, and to set common priorities during emergency events. TECO also reported conducting damaged facility reporting training, as well as sharing information on the costs and benefits of undergrounding its electric facilities.

- Gulf reported inspecting 103% of its wood poles required to meet the 2007 contribution to its 8-year inspection plan. Gulf clears vegetation from its feeder circuits on a 3-year trim cycle. Gulf reported clearing 300% of feeder circuits for the 2007 contribution of the 3-year plan. Gulf clears vegetation from its lateral circuits on a 6-year trim cycle. Gulf reported clearing 102% of lateral circuits for the 2007 contribution to its 6-year plan.

  Gulf's coordination with local governments in 2007 included surveying each EOC director in its service region to ascertain Gulfs participation level, responsiveness, and presence in the respective EOC. Gulf also reports hosting community leader forums each year to update local government and community leaders on Gulf's storm plans and to seek comment on community-specific issues.

- FPUC reports implementing a 3-year main feeder and 6-year lateral vegetation management program during 2007. FPUC reports its new GIS system and tracking procedures will enable data production for 2008.

  FPUC reports participating in regularly scheduled communication events with county emergency response organizations within its service territory. FPUC also reports that its NE division has been asked to participate in the Underground Utilities committee of the City of Fernandina Beach.

Assessing Service Reliability

The assessment of an IOU's service reliability is made primarily through a detailed review of established service reliability metrics pursuant to Rule 25-6.0455, Florida Administrative Code (F.A.C.).[1] Reliability metrics are intended to reflect changes over time in system average performance, regional performance, and sub-regional performance. For a given system, increases in the value of a given reliability metric may denote declining reliability in the service being provided. Comparison of the year-to-year levels of the reliability metrics may reveal changes in performance which indicate the need for additional work in one or more areas. A utility's level of storm hardening activity is reviewed to gain insight into factors contributing to the observed trends in the performance metrics.[2, 3] Additional insight into potential changes in service reliability can be found through inter-utility comparisons of reliability data and reliability-related complaints addressed by the Florida Public Service Commission (Commission). Finally, audits are performed where additional scrutiny is deemed necessary, based on observed patterns, and to ensure the reported data are reliable.

Prior to 2006, Rule 25-6.0455, F.A.C., required the IOUs to file distribution reliability metrics to track adjusted performance that excluded events such as planned outages for maintenance, generation disturbances, transmission disturbances, wildfires, and extreme acts of nature such as tornadoes and hurricanes. The "adjusted" data provide an indication of the distribution system performance on a normal day-to-day basis but does not reveal the impact of excluded events on reliability performance.

With the active hurricane years of 2004 and 2005, the importance of collecting reliability data that would reflect the total or "actual" reliability experience from customers' perspective became apparent. Complete unadjusted service reliability data was considered essential to assess service performance during hurricanes. In June 2006, Rule 25-6.0455, F.A.C., was revised to require each IOU to provide both "actual" and "adjusted" performance data for the prior year. The scope of the IOUs' Annual Distribution Service Reliability Report was also expanded to include status reports on the various storm hardening initiatives required by the Commission.[4] Staff held a workshop with the IOUs and interested parties in October 2006 to discuss the expected content of the more comprehensive reports which would be due on March 1, 2007, and March of subsequent years.

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[1]The Commission does not have rules requiring municipal electric utilities and rural electric cooperative utilities to file service reliability metrics.
[2]Rule 25-6.0342, F.A.C., effective February 1, 2007, requires investor-owned electric utilities to file comprehensive storm hardening plans at least every three years.
[3]Rule 25-6.0343, F.A.C., effective December 12, 2006, requires municipal electric utilities and rural electric cooperative utilities to report annually, by March 1, the extent to which their construction standards, policies, practices, and procedures are designed to storm-harden their transmission and distribution facilities.
[4]Wooden Pole Inspection Orders: Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 060078-EI; and Order Nos. PSC-06-0778-PAA-EU, issued September 18, 2006, PSC-07-0078-PAA-EU, issued January 29, 2007, in Docket No. 060531-EU.
Storm Hardening Initiative Orders: PSC-06-0351-PAA-EI, issued April 25, 2006; PSC-06-0781-PAA- EI, issued September 19, 2006; PSC-06-0947-PAA-EI, issued November 13, 2006; and PSC-07-0468-FOF-EI, issued May 30, 2007, in Docket No. 060198-EI.

The reports filed on March 1, 2008, included (1) actual 2007 service reliability data; (2) adjusted 2007 distribution service reliability data; (3) actual and adjusted performance assessments in four areas: system-wide, operating region, feeder, and cause of outage events; and (4) complaints. The reports also summarized the storm hardening activities of the IOU.

Conclusions

The March 1, 2008 reports of Florida Power & Light Company (FPL), Progress Energy Florida, Inc. (PEF), Tampa Electric Company (TECO), Florida Public Utilities Company (FPUC), and Gulf Power Company (Gulf) were sufficient to perform this review.

Based on the data filed to date, staff has not observed any trends in service reliability warranting an increased level of investigation, such as a focused audit or other formal proceeding before the Commission. Staff will continue to monitor and engage each company on service reliability matters. The following company-specific summaries provide highlights of the observed patterns.

Service Reliability of Florida Power & Light Company

In 2007, FPL's adjusted distribution reliability, as measured by system average interruption duration index (SAIDI), was approximately 73 minutes. This figure is roughly a 1.4% improvement over the company's 2006 performance, when its average interuption was 74 minutes. FPL believes this improved SAIDI performance is a direct result of its storm hardening and preparedness initiatives, as well as moderate storm seasons in 2006 and 2007. FPL's adjusted average frequency of momentary feeder events (MAIFIe) increased by approximately 3% from 2006 to 2007.

On an adjusted basis, FPL's 2007 average frequency of service interruptions (SAIFI) decreased by approximately 6%, indicating that FPL's customers were experiencing fewer interruptions on a system-wide basis. Despite improvement in FPL's adjusted SAIDI and SAIFI indices, its adjusted average duration of outage events (L-Bar) index increased from 205 minutes in 2006, to 211 minutes (3%) in 2007. FPL's adjusted average time to restore service to interrupted customers (CAIDI) increased by roughly 4% from 2006 to 2007.

Service Reliability of Progress Energy Florida

PEF's 2007 adjusted SAIDI index was approximately 78 minutes. This result is roughly 3 additional minutes (4%) of outage duration than in 2006. PEF's adjusted MAIFIe increased by approximately 5% from 2006 to 2007. This increase indicates that a greater number of momentary service interuptions lasting less than one minute were expierenced by PEF's customers in 2007 over the prior year.

PEF's 2007 adjusted SAIFI increased by approximately 4%, indicating that PEF's customers were experiencing a higher frequency of interruptions on a system-wide basis. PEF's adjusted L-Bar increased slightly, from 121 minutes in 2006, to 122 in 2007. PEF's adjusted CAIDI was approximately 69 minutes in 2006 and 2007.

Service Reliability of Tampa Electric Company

In 2007, TECO's adjusted SAIDI index was approximately 77 minutes. This figure represents an increase of roughly 8 minutes (12%) in average outage duration over 2006. TECO's adjusted MAIFIe increased by approximately 9% from 2006 to 2007. These increases in index value demonstrate a decreasing reliability trend as measured by SAIDI and MAIFIe.

TECO's adjusted SAIFI increased approximately 15% in 2007, indicating a higher frequency of power interruptions than in 2006. TECO's adjusted L-Bar decreased slightly, from approximately 163 minutes in 2006 to 162 in 2007 (<1%). TECO's adjusted CAIDI decreased by approximately 4% from 2006 to 2007. The decreases in TECO's L-Bar CAIDI index demonstrate improved reliability in these areas.

Service Reliability of Gulf Power Company

Gulf's adjusted 2007 distribution reliability indices show a significant improvement from the previous year. Gulf's 2007 adjusted SAIDI index decreased by 39% in 2007, representing 80 fewer minutes than in 2006. Gulf's adjusted MAIFIe also decreased significantly, down approximately 18% from 2006 to 2007. The decreases in SAIDI and MAIFIe indices suggest improved reliability.

Gulf's 2007 adjusted SAIFI index indicates an 8% decrease from 2006. Gulf's adjusted L-Bar also decreased, from 170 in 2006 to 132 (22%) in 2007. Gulf's adjusted CAIDI showed a marked improvement over 2006, decreasing by approximately 34%. Such index decreases demonstrate improved reliability.

Service Reliability of Florida Public Utilities Company

FPUC's 2007 reported data suggest a significant improvement in system reliability from 2006. FPUC attributes these improvements to maintenance programs and more favorable weather conditions than in previous years. FPUC's SAIDI index was approximately 78 minutes in 2007, nearly 76 minutes (49%) less than the average outage duration in 2006. FPUC is exempt from reporting MAIFIe due to serving fewer than 50,000 customers.

FPUC's 2007 average SAIFI decreased significantly in 2007, by 22% from 2006. FPUC's improved reliability was also demonstrated by its L-Bar, which decreased from 84 in 2006 to 77 in 2007 (8%). FPUC's CAIDI also decreased significantly in 2007, down 35% from 2006. FPUC's 2007 reliability indices suggest that its overall system experienced outages that were less frequent and shorter in duration than in 2006.

Introduction

The Commission has the jurisdiction to monitor the quality and reliability of electric service provided by Florida's investor-owned electric utilities for maintenance, operational, and emergency purposes.[5]

Monitoring service reliability is achieved through a review of service reliability metrics submitted to the Commission by the IOUs pursuant to Rule 25-6.0455, Florida Administrative Code (F.A.C.).[6] Service reliability metrics are intended to reflect changes over time in system average performance, regional performance, and sub-regional performance. For a given system, increases in the value of a given reliability metric denote declining reliability in the service being provided. Comparison of the year-to-year levels of the reliability metrics may reveal changes in performance which indicate the need for additional work in one or more areas.

A utility's level of storm hardening activity contributes both to day-to-day service reliability and emergency response. Accordingly, a review of a utility's storm hardening activities can provide insight into factors contributing to the observed trends in the reliability metrics. Additional insight into potential changes in service reliability can be found through inter-utility comparisons of reliability data and reliability-related complaints addressed by the Commission. Finally, audits are performed where additional scrutiny is warranted, based on the observed patterns, and to confirm the reported data is reliable.

Throughout this review, emphasis is placed on observations that suggest meaningful declines in service reliability and areas where additional scrutiny or remedial action may be required by the company.

[5] Sections 366.04(2)(c) and 366.05, Florida Statutes.
[6] The Commission does not have rules requiring municipal electric utilities and rural electric cooperative utilities to file service reliability metrics.

Background

Prior to 2006, Rule 25-6.0455, F.A.C., required the IOUs to file distribution reliability metrics that excluded the effects of events such as planned outages for maintenance, generation disturbances, transmission disturbances, wildfires, and extreme acts of nature such as tornadoes and hurricanes. The "adjusted" data provide an indication of the distribution system performance on a normal day-to-day basis but do not reveal the impact of excluded events on reliability performance.

With the active hurricane years of 2004 and 2005, the importance of collecting reliability data that would reflect the total or "actual" reliability experience from the customers' perspective became apparent. Complete unadjusted service reliability data was determined to be required for assessing service performance during hurricanes. In June 2006, Rule 25-6.0455, F.A.C., was revised to require each IOU to provide both "actual" and "adjusted" performance data for the prior year. The scope of the IOUs' Annual Distribution Service Reliability Report was expanded to include status reports on the various storm hardening initiatives required by the Commission.[7] Staff held a workshop with the IOUs and interested parties in October 2006 to discuss the expected content of the more comprehensive reports which would be due on March 1, 2007, and each March of subsequent years.

The reports filed on March 1, 2008, included (1) actual 2007 distribution service reliability data; (2) adjusted 2007 distribution service reliability data; (3) actual and adjusted performance assessments in five areas: system-wide, operating region, feeder, and cause of outage events; and (4) complaints. The reports also summarized the storm hardening activities for the IOU.

Review Outline

This review relies primarily on the March 1, 2008 reports for recent reliability performance data and storm hardening activities. A section addressing trends in reliability-related complaints is also included. This report consists of five sections.

Section 1: Addresses storm hardening activities such as pole strength inspections, vegetation management, and other initiatives.

Section 2: Addresses each IOU's actual 2007 distribution service reliability and support for each of its adjustments to the actual service reliability data.

Section 3: Addresses each IOU's 2007 distribution service reliability based on adjusted service reliability data.

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[7]Wooden Pole Inspection Orders: Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 060078-EI; and Order Nos. PSC-06-0778-PAA-EU, issued September 18, 2006, PSC-07-0078-PAA-EU, issued January 29, 2007, in Docket No. 060531-EU.
Storm Hardening Initiative Orders: PSC-06-0351-PAA-EI, issued April 25, 2006; PSC-06-0781-PAA- EI, issued September 19, 2006; PSC-06-0947-PAA-EI, issued November 13, 2006; and PSC-07-0468-FOF-EI, issued May 30, 2007, in Docket No. 060198-EI.

Section 4: Addresses inter-utility comparisons and the volume of reliability-related customer complaints.

Section 5: Appendices containing detailed utility-specific data.

Section I. Storm Hardening Activities

The hurricanes of 2004 and 2005 caused extensive damage, resulting in significant storm restoration costs and prolonged electric service interruptions to millions of Florida's electric utility customers. On January 23, 2006, the Commission conducted a workshop to discuss the damage to electric utility facilities from these hurricanes and to explore ways of minimizing future storm damages and customer outages. State and local government officials, independent technical experts, and Florida's electric utilities participated in the workshop.

On February 7, 2006, the Commission voted to require the IOUs and local exchange telephone companies to begin implementing an eight-year inspection cycle of their respective wooden poles.[8, 9] On February 27, 2006, at an internal affairs conference, the Commission was briefed on additional recommended actions to address the effects of extreme weather events on electric infrastructure. The Commission also heard comments from interested persons and Florida's electric utilities regarding staff's recommended actions. Ultimately, the Commission made the following decisions:

(1) All Florida electric utilities, including municipal utilities and rural electric cooperative utilities, would provide an annual Hurricane Preparedness Briefing.

(2) Staff would file a proposed agency action recommendation for the April 4, 2006 agenda conference requiring each IOU to file plans and estimated implementation costs for ongoing storm preparedness initiatives.

(3) A docket would be opened to initiate rulemaking to adopt distribution construction standards that are more stringent than the minimum safety requirements of the National Electrical Safety Code (NESC).

(4) A docket would be opened to initiate rulemaking to identify areas and circumstances where distribution facilities should be required to be constructed underground.

On April 25, 2006, the Commission issued Order No. PSC-06-0351-PAA-EI, requiring the IOUs to file plans and estimated implementation costs for ten ongoing storm preparedness initiatives (Ten Initiatives) on or before June 1, 2006.[10] The status of these initiatives is discussed in the individual reports for 2007.

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[8]Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 060078-EI, <u>In re: Proposal to require investor-owned electric utilities to implement ten-year wood pole inspection program.</u> Order No. PSC-06-0168-PAA-TL, issued March 1, 2006, in Docket No. 060077-TL, <u>In re: Proposal to require local exchange telecommunications companies to implement ten-year wood pole inspection program.</u>

[9]Rule 25-6.0343, F.A.C., effective December 12, 2006, requires municipal electric utilities and rural electric cooperative utilities to report annually, by March 1, their standards, policies, practices, and procedures regarding storm hardening, including wooden pole inspections.

[10]Docket No. 060198-EI, <u>In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates.</u>

The Ten Initiatives are:

(11) A three-year vegetation management cycle for distribution circuits
(12) An audit of joint-use attachment agreements
(13) A six-year transmission structure inspection program
(14) Hardening of existing transmission structures
(15) A transmission and distribution geographic information system
(16) Post-storm data collection and forensic analysis
(17) Collection of detailed outage data differentiating between the reliability performance of overhead and underground systems
(18) Increased utility coordination with local governments
(19) Collaborative research on effects of hurricane winds and storm surge
(20) A natural disaster preparedness and recovery program

These Ten Initiatives were not intended to encompass all possible ongoing storm preparedness activities. Rather, the Commission viewed these initiatives as the starting point of an ongoing process.[11, 12]

Separate from the Ten Initiatives, the Commission established rules addressing storm hardening of transmission and distribution facilities for all of Florida's electric utilities.[13, 14, 15] Each IOU, pursuant to Rule 25-6.0342, F.A.C., is required to file a storm hardening plan for Commission review and approval at least every three years. On May 7, 2007, the four major IOUs filed storm hardening plans that included the wooden pole inspection program and the Ten Initiatives. However, FPUC requested to file its storm hardening plan as part of its petition for a general rate increase. This request was approved by Order No. PSC-08-0327-FOF-EI, and FPUC's storm hardening plan was addressed in Docket No. 070304-EI.

A consolidated public hearing was held on October 3-4, 2006, to address the storm hardening plans of the four major IOUs. On December 4, 2006, the Commission voted to

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[11] See page 2 of Order No. PSC-06-0947-PAA-EI, issued November 13, 2006, in Docket No. 060198-EI, In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates.

[12] The Commission addressed the adequacy of the IOUs' plans for implementing the Ten Initiatives by Order Nos. PSC-06-0781-PAA-EI, PSC-06-0947-PAA-EI, and PSC-07-0468-FOF-EI. In 2006, the municipal and rural electric cooperative utilities voluntarily provided summary statements regarding their implementation of the Ten Initiatives. Prospectively, reporting from these utilities is required pursuant to Rule 25-6.0343, F.A.C.

[13] Order No. PSC-06-0556-NOR-EU, issued June 28, 2006, in Docket No. 060172-EU, In re: Proposed rules governing placement of new electric distribution facilities underground, and conversion of existing overhead distribution facilities to underground facilities, to address effects of extreme weather events, and Docket No. 060173-EU, In re: Proposed amendments to rules regarding overhead electric facilities to allow more stringent construction standards than required by National Electric Safety Code.

[14] Order Nos. PSC-07-0043-FOF-EU and PSC-07-0043A-FOF-EU.

[15] Order No. PSC-06-0969-FOF-EU, issued November 21, 2006, in Docket No. 060512-EU, In re: Proposed adoption of new Rule 25-6.0343, F.A.C., Standards of Construction - Municipal Electric Utilities and Rural Electric Cooperatives.

approve the storm hardening plans and required the next storm plans to be filed by May 1, 2010.[16]

The following subsections provide a summary of each IOU's programs addressing an eight-year wooden pole inspection program and the Ten Initiatives.

Eight-Year Wooden Pole Inspection Program

Order Nos. PSC-06-0144-PAA-EI and PSC-07-0078-PAA-EI require each IOU to inspect 100% of their installed wooden poles every 8 years. FPUC's implementation of the eight-year wooden pole inspection program was approved on May 19, 2008, by Order No. PSC-08-0327-FOF-EI filed in Docket No. 070304-EI, FPUC's request for a general rate increase.

Table 1-1 shows a summary of the quantities of wooden poles inspected by all IOUs in 2007.

Table 1-1. 2007 Wooden Pole Inspection Activity Summary

IOU	2007 Installed Wooden Poles	Average Annual Inspections to Meet 8-Year Cycle	2007 Pole Inspections					2007 Variance from 8-Year Cycle	
			Planned		Completed		Variance		
			Volume	% of Average Annual Inspections Required to Meet 8-Year Plan	Volume	% of Average Annual Inspections Required to Meet 8-Year Plan	% of Planned	Volume	% of Average Annual Inspections Required to Meet 8-Year Plan
FPL	1,069,819	133,727	120,043	90%	128,885	96%	7%	-4,842	-4%
PEF	836,002	104,500	103,650	99%	108,840	104%	5%	4340	4%
TECO	307,218	38,402	42,343	110%	53,532	139%	29%	15,130	39%
Gulf	255,950	31,994	32,000	100%	33,026	103%	3%	1,032	3%
FPUC	25,620	3,203	2,798	87%	2,798	87%	0%	-405	-13%

[16] Order No. PSC-06-0969-FOF-EU, issued November 21, 2006, in Docket No. 060512-EU, In re: Proposed adoption of new Rule 25-6.0343, F.A.C., Standards of Construction - Municipal Electric Utilities and Rural Electric Cooperatives.

Table 1-2 shows the projected 2008 wooden pole inspection activity summary.

Table 1-2. Projected 2008 Wooden Pole Inspection Activity Summary

IOU	2007 Installed Wooden Poles	2008 Planned Inspections		2007-2008 Cumulative			
				% of Average Annual Inspections Required to Meet 8-Year Plan	Planned	Estimated Variance from 8-Yr Cycle	
		Volume	% of Average Annual Inspections Required to Meet 8-Year Plan		Volume	Volume	% of Average Annual Inspections Required to Meet 8-Year Plan
FPL	1,069,819	133,480	100%	267,455	262,365	-5,090	-2%
PEF	836,002	103,000	99%	209,001	211,890	2,839	1%
TECO	307,218	41,617	108%	76,805	95,149	18,344	24%
Gulf	255,950	32,000	100%	63,988	65,026	1,038	2%

The annual variances shown in Tables 1-1 and 1-2 are allowable so long as each utility achieves 100% inspection within an 8-year period. Staff will continue to monitor each utility's performance.

Ten Initiatives

Three-Year Vegetation Management Cycle for Distribution Circuits

Since feeder circuits are the main arteries from the substations to the local communities, these circuits are targeted for frequent vegetation management. The approved plans of all IOUs require a maximum of a three-year trim cycle for overhead feeder circuits and a six-year trim cycle for lateral circuits.

Table 1-3 is a summary of 2007 and projected 2008 feeder vegetation management activities.

Table 1-3. 2007-2008 Vegetation Clearing from Feeder Circuits

IOU	Plan Trim Cycle (Years)	Total Miles	Avg. Annual Miles[17]	2007 Miles		Projected 2008 Miles	
				Miles Trimmed	% of Annual Cycle	Estimated Trim Miles	% of Annual Cycle
FPL	3	13,469	4,490	4,454	99%	4,421	99%
PEF	3	3,800	1,267	2,112	167%	337	27%
TECO	3	1,724	575	363	63%	376	65%
Gulf	3	1,878	626	1,878	300%	803	43%

[17] Not adjusted for growth. Discussions are anticipated as to an appropriate methodology to account for growth.

Table 1-4 is a summary of 2007 and projected 2008 lateral vegetation management activities.

Table 1-4. Vegetation Clearing from Lateral Circuits

IOU	Plan Trim Cycle (Years)	Total Miles	Plan Average Annual Miles[18]	2007 Miles		Projected 2008 Miles	
				Miles Trimmed	% of Annual Cycle	Estimated Trim Miles	% of Annual Cycle
FPL[19]	6	22,444	3,741	2,215	59%	2,007	54%
PEF	5	14,200	2,840	2,203	78%	3,267	150%
TECO	3	4,397	1,466	945	64%	642	44%
Gulf	6	3,981	664	675	102%	843	127%

In addition to the planned trimming cycle, each IOU also performs hot-spot trimming and mid-cycle trimming to address rapid growth problems. Tables 1-3 and 1-4 do not reflect hot-spot trimming and mid-cycle trimming activities. An additional factor to consider is that not all miles of overhead distribution circuits require vegetation clearing. Factors such as hot-spot trimming and open areas contribute to the apparent variances from the approved plans. Annual variances as seen in Tables 1-3 and 1-4 are allowable as long as each utility achieves 100% completion within the cycle-period stated in its approved plan for feeder and lateral circuits.

Audit of Joint Use Agreements

The Commission requires each IOU to actively monitor the impact of attachments by other parties to ensure the attachments conform to the IOU's strength requirements without compromising storm performance. All IOUs perform pole strength assessments in conjunction with their eight-year wooden pole inspection programs. Additionally, field surveys are performed to verify that the third-party attachments in the field comply with the terms and conditions of existing joint use agreements. These field surveys typically focus on discovering attachments that were previously not known or are inconsistent with the joint use agreements. On average, field surveys occur on a five-year cycle. The following are some 2007 highlights:

- FPL audits approximately 20% of its joint use poles annually. The 2007 audit revealed 1,798 unauthorized attachments. FPL strength tested 98,430 poles, of which 2,393 were found to be overloaded.

- PEF audited its entire system of jointly used transmission and distribution poles in 2007 and found no unauthorized attachments. PEF strength tested 62,547 poles, of which 299 were found to be overloaded.

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[18] Not adjusted for growth. Discussions are anticipated as to an appropriate methodology to account for growth.

[19] FPL's approved plan is required to achieve its 6-year lateral trim cycle by 2013.

- TECO audited 25% of its jointly used distribution system in 2007. TECO was unable to determine the number of unauthorized attachments as of the March 1, 2008 filing date of its reliability report. TECO strength tested 50,996 poles, of which 1,457 were found to be overloaded.

- Gulf audited its entire joint use overhead distribution system in 2006. Gulf's joint use audit occurs on a five-year basis. Gulf's next entire-system audit is scheduled for 2011. Gulf's 2006 audit discovered 6,379 unauthorized attachments. Gulf reported strength testing 500 poles, of which 41 were found to be overloaded.

- FPUC reported that it had not performed any joint use pole audits in 2007. FPUC plans to conduct a joint use pole audit contingent upon the outcome of its 2008 FPSC rate case proceeding. FPUC plans to file its petition for a rate increase on or before December 23, 2008.

Six-Year Transmission Inspections

The Commission required each IOU to develop a plan to fully inspect, on a six-year cycle, all transmission structures and substations, and all hardware associated with these facilities. Approval of any alternative to a six-year cycle must be shown to be equivalent or better than a six-year cycle in terms of cost and reliability in preparing for future storms. The approved plans for FPL, TECO, and Gulf require full inspection of all transmission facilities within a six-year cycle. On an annual average basis, a full inspection means inspecting 16.7% of the system. PEF, which already had a program indexed to a five-year cycle, continues with its five-year program. Such variances are allowed so long as each utility achieves 100% completion within a six-year period, as outlined in Order No. PSC-06-0198-EI dated April 4, 2006.

- FPL reported inspecting 53% of its transmission circuits and 100% of its transmission substations in 2007.

- PEF reported inspecting 37% of its transmission circuits and 100% of its transmission substations in 2007.

- TECO reported inspecting 22% of its transmission circuits and 100% of its transmission substations in 2007.

- Gulf reported inspecting 100% of its transmission substations in 2007. While Gulf reports that they do not inspect by transmission circuit, they instead target certain poles and structures when they are inspecting the transmission system. During these targeted inspections, all line and pole hardware associated with the transmission poles and structures is also inspected. Gulf reports that it conducts an annual minimum of four routine aerial patrols of all structures on its transmission system and states that it is on target to comply with the FPSC six-year inspection cycle requirement.

- FPUC reported inspecting 100% of its transmission circuits and 92% of its transmission substations in 2007.

Hardening of Existing Transmission Structures

The Commission required IOUs to show the extent of utility efforts in this area, including the scope of activity and the criteria used for selecting transmission upgrades and replacements. No specific activity was ordered other than developing a plan and reporting on storm hardening of existing transmission structures. In general, all IOUs' plans continued pre-existing programs that focus on upgrading older wooden transmission poles. Below are some 2007 highlights and projected 2008 activities for each IOU.

- FPL reported replacing 339 single pole un-guyed wood (SPUW) transmission structures and 773 ceramic post transmission line insulators (CPOC) in 2007. FPL has budgeted approximately $6 million for the hardening of its existing transmission structures in 2008.

- PEF reported replacing a total of 2,470 structures in 2007. PEF's 2008 goal is to replace 1,800 structures as part of routine business expenditures including highway relocations, line rebuilds, and maintenance charge outs for a budgeted $95.3 million.

- TECO reported replacing a total of 524 structures in 2007. TECO's 2008 goal is to replace 660 structures for a budgeted $10.85 million.

- Gulf Power reported hardening a total of 342 transmission structures in 2007 by adding storm guys and replacing wood crossarms with steel crossarms. Gulf's 2008 goal is to storm harden 300 transmission structures for a budgeted $600,000. Additionally, Gulf's 6-Year Transmission Inspection Program resulted in the replacement of 314 transmission poles in 2007.

- FPUC: FPUC claims it is still in the process of finalizing the scope of its storm hardening plan and subsequent implementation. However, FPUC reported replacing 15 45-foot Class 3 wood class G poles along its "prison feeder" route. FPUC also reported relocating certain feeders for its hardening program. In 2008, FPUC plans to rebuild its Highway 90 East Feeder that serves the Marianna sewer treatment plant, a critical infrastructure facility.

A Transmission and Distribution Geographic Information System

Post-Storm Data Collection and Forensic Analysis

Collection of Detailed Outage Data Differentiating Between the Reliability Performance of Overhead and Underground Systems

These three initiatives are addressed together because effective implementation of any one initiative is dependent on effective implementation of the other two initiatives. The five IOUs have geographic information system (GIS) programs and programs to collect post-storm data on competing technologies, perform forensic analysis, and assess the reliability of overhead and underground systems on an ongoing basis. Differentiating between overhead and underground reliability performance and costs is still difficult because underground facilities are typically connected to overhead facilities and the interconnected systems of the IOUs address reliability on an overall basis. Below are some 2007 highlights and projected 2008 activities for each IOU.

- In 2007, FPL reports that it continued efforts to better capture and store asset data for its distribution system. The reported upgrades include improving systems to better collect and store post-hurricane forensic data, adding field inspection data associated with FPL's pole inspection program, preparing for the incorporation of joint use data, as well as preparing to capture information associated with FPL's hardening activities. These activities will continue into 2008. FPL reports that a forensic module was implemented in 2007 in order to provide one single software tool for forensic work. Since no major storms occurred in 2007, FPL reports that no forensic teams were deployed. In addition, FPL reports creating a process "framework" in 2007 to standardize and automate the loading of pole inspection data into the GIS. FPL plans to use an extension of this "framework" to have joint use data, load calculation data, and hardening level data in its GIS platform in 2008. Since almost all of FPL's distribution feeders contain both overhead and underground facilities, FPL reports that it will use laterals as proxies for assessing overhead and underground system performance.

- PEF reports that its transmission facility data was added to the GIS in 2007; distribution facility data was added in 2006. PEF states that the pole location information is now part of the data available for analysis using GIS applications. PEF's approach to differentiating between overhead and underground facility performance includes assessing GIS, outage management, and customer service information systems. Since PEF did not experience a hurricane event in 2007, no significant outage data differentiating between the reliability performance of overhead and underground systems was provided.

- TECO reports plans to complete the implementation of its GIS resource in the summer of 2008, and to integrate the GIS with forensics data tracking by the 2009 storm season. TECO states that the GIS will then contain all facility data for transmission, substation, distribution, and lighting facilities. TECO considers its new GIS to be a critical component of the company's storm hardening plan moving forward. TECO reports that the system will enhance post-storm damage assessment, forensic analysis, joint use administration, and an evaluation of the company's construction standards and potential hardening projects. TECO provided data illustrating overhead and underground system performance during Tropical Storm Barry. This information seems to indicate that underground systems are less prone to damage during such weather conditions. However, some significant outages did result from underground systems being affected by water infiltration, illustrating that even the underground systems are not safe from storms.

- Gulf has captured all overhead and underground distribution equipment in their new Distribution Geographic Information System, DistGIS. Which includes conductors; regulators; capacitors and switches; protective devices such as reclosers, sectionalizers, fuses, and transformers. According to Gulf, DistGIS provides facility information for it to use with collected forensic data to assess performance of overhead and underground systems in the event of a major storm. During 2007, Gulf states that it worked to finalize its forensic process and implemented additional record keeping and data analysis associated with overhead and underground outages. Since Gulf was not affected by any major named storm in 2007, no outage data differentiating between the reliability performance of the overhead and underground systems was reported.

- FPUC reports that the initial installations of its GIS for the NE Division were completed in 2007; the NW Division was completed in 2005. FPUC states that the distribution and transmission assets are continuing to be populated in these systems. FPUC expects the GIS to improve service delivery as well as provide additional data for inspections, outage management, and work management activities. FPUC considers the GIS to be a critical part of its vegetation management activities, storm hardening plans, post-storm assessments, and overhead and underground outage performance. FPUC reports that it has not formally established a post-storm data collection and forensic analysis program at this time, but plans to hire a consultant to perform post-storm forensic analysis and restoration process integration and to establish methods for data collection using the GIS and Outage Management Systems. A database of transmission and distribution assets to use in post-storm forensic analysis will be established on a geographic basis. FPUC reports that since no severe storm related outages occurred in 2007, no reliability performance comparisons between overhead and underground facilities were provided.

Increased Utility Coordination with Local Governments

The Commission's goal with this program is to promote ongoing dialogue between IOUs and local governments on matters such as vegetation and underground construction, in addition to the general need to increase pre- and post-storm coordination. The increased coordination and communication is intended to promote IOU collection and analysis of more detailed information on the operational characteristics of underground and overhead systems. This additional data is also necessary to more fully inform customers and communities who are considering converting existing overhead facilities to underground facilities (undergrounding), as well as to assess the most cost-effective storm hardening options.

Each IOU's external affairs representatives or designated liaisons are responsible for engaging in dialog with local governments on issues pertaining to underground issues, vegetation management, public rights-of-way use, critical infrastructure projects, other storm-related topics, and day-to-day matters. Additionally, each IOU assigns staff to each county emergency operations center to participate in joint training exercises and actual storm restoration efforts. The IOUs now have outreach and educational programs addressing underground construction, tree placement, tree selection, and tree trimming practices. Below are some 2007 highlights for each utility.

- FPL's External Affairs organization communicates with local government and community leaders to identify and resolve emergency event concerns of the community it serves. In 2007, FPL reported holding various meetings and workshops with local governments and county EOCs. The focus of these meetings was to discuss FPL storm hardening activities and to examine better ways to collaborate with local government during emergency situations.

- PEF reports coordinating year-round with local government through its community relations team. PEF's representatives held various meetings and expositions with local government, county EOCs, and first responders in 2007. These events included discussions to coordinate emergency planning activities, training activities, and community education seminars.

- TECO reports conducting workshops in 2007 with local government and county EOCs to discuss pre-storm preparedness and hazard mitigation, and to set common priorities during emergency events. TECO also reported conducting damaged facility reporting training, as well as sharing information on the costs and benefits of undergrounding its electric facilities.

- Gulf reports continuing coordination with local governments and EOCs in 2007. Gulf surveyed each EOC director in its service region to ascertain its participation level, responsiveness, and presence in the respective EOC. Gulf reports that all EOC directors described Gulf's coordination efforts to be outstanding. Gulf also hosts community leader forums each year to update local government and community leaders on Gulf's storm plans and to seek comment on community-specific issues.

- FPUC reports continuing coordination with local city/county emergency service agencies within its service areas. FPUC also reports participating in regularly scheduled communication events with county emergency response organizations within its service territory.

Collaborative Research on Effects of Hurricane Winds and Storm Surge

Prior to 2006, the Commission observed that the utilities appeared to be unaware of work being done by universities to study the effects of hurricane winds and storm surge in Florida. Each utility appeared engaged in independent efforts to gather its own data with little, if any, coordination of resources and information. The Commission found that Florida would be better served by consolidating utility resources through a centrally coordinated research and development effort with universities as well as research organizations. The same data is needed by the utility to address storm hardening options that reduce storm damage, storm restoration costs, and customer outages.

In response to Commission directives, the electric utilities established a non-profit, member-financed organization to coordinate all research efforts through the Public Utility Research Center, located in the Warrington College of Business at the University of Florida. The members include all electric municipal utilities, retail electric cooperative utilities, and IOUs within Florida. The administrative requirements were codified in a memorandum of understanding. The resulting collaborative research programs address three areas: hurricane wind effects, vegetation management, and undergrounding of electric utility infrastructure.

Hurricane Wind Effects. The wind research project is a long-term effort that will collect data on hurricane force wind impacts on electric facilities through observations of actual events and experimentation. The wind information is needed to fill a gap in current utility knowledge. Absent the research effort, each utility would have very little objective wind data which is essential for effective forensic assessments. The knowledge developed through wind research will enable future utility planners to evaluate storm hardening alternatives prior to implementation, thereby avoiding a potentially costly trial-by-error approach. No end date for the wind research program has been set.

Vegetation Management. The vegetation management research project is directed at improving vegetation management practices so that outages, post-storm restoration efforts, and overall vegetation management costs are reduced. An industry workshop addressing best practices in vegetation management was held on March 5-6, 2007, in Orlando, and was attended by 30 electric utilities. A report summarizing the results from the best practice workshop was completed April 17, 2007.[20] The top five best practices ranked by number of votes received are:

- State law (referenced the law in California) giving utility right to trim/remove (26 votes)
- Adequate financial resources to maintain vegetation management cycles (13 votes)
- City partnership to work with homeowner associations/city foresters (10 votes)
- Herbicide use to control growth on vegetation and in ground (8 votes)
- Directional pruning (7 votes)

Additionally, areas for improvement were addressed. The top five areas for improvement in vegetation management programs ranked by the number of votes received are:

- Better education of customers and public (22 votes)
- State laws to support tree removals (18 votes)
- Maintenance of some circuits from station to the end of the line (3 votes)
- Access (3 votes)
- Chemical applications (3 votes)

The report on the best vegetation management practices does not discuss any future plans for additional review. The report notes a suggested role for the Commission in providing regular public service announcement campaigns.

Undergrounding of Electric Utility Infrastructure. The undergrounding research project is structured in three phases: Phase 1 combines and analyzes the results of existing research, reports, and case studies; Phase 2 examines Florida-specific case studies of actual projects in which overhead facilities have been converted to underground; and Phase 3 develops and tests a methodology for identifying and evaluating costs and benefits of underground-specific facilities in Florida.

[17] "Report on the Workshop for Best Practices in Vegetation Management," April 17, 2007, <http://www.floridapsc.com/utilities/electricgas/EIProject/docs/VegetationManagementWorkshopReport.pdf>.

Phase 1 was completed on February 28, 2007;[21] Phase 2 was completed on August 6, 2007;[22] and Phase 3 was completed on May 21, 2008.[23] As with the Phase 1 and Phase 2 reports, the Phase 3 report noted that the conversion of overhead to underground is costly, and these costs almost always exceed the quantifiable benefits of reduced operation and maintenance costs and reduced hurricane damage costs. The report also noted that there has been no consistent approach to computing costs and benefits of proposed undergrounding projects, making studies difficult to interpret and use for making decisions. The Phase 3 report presents a methodology for estimating the costs and benefits of potential undergrounding projects and other activities that have an impact on hurricane performance, such as the hardening of overhead systems. The methodology is specific to Florida and is based on a detailed simulation of the following components: hurricane model, equipment damage model, restoration model, and cost-benefit model.

The spreadsheet application allows a range of options to be considered and compared based on their incremental costs and benefits. The Phase 3 report concludes that the methodology presented attempts to add consistency in analyzing costs and benefits. The methodology can provide insights into how different variables affect costs and benefits of undergrounding.

A Natural Disaster Preparedness and Recovery Program

Each IOU is required to maintain a copy of its current formal disaster preparedness and recovery plan with the Commission. A formal disaster plan provides an effective means to document lessons learned; improve disaster recovery training, pre-storm staging activities, post-storm recovery; collect facility performance data; and improve forensic analysis. Additionally, the IOUs participate in the Commission's annual pre-storm preparedness briefing which focuses on the extent to which all Florida electric utilities and telecommunications companies are prepared for potential hurricane events.

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[21] Undergrounding Assessment Phase 1 Report, *Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion,* issued February 28, 2007, <http://www.psc.state.fl.us/utilities/electricgas/EIProject/docs/InfraSourcePhase1FinalReport20070228.pdf>.

[22] Undergrounding Assessment Phase 2 Report, *Undergrounding Case Studies,* issued August 6, 2007, < http://www.psc.state.fl.us/utilities/electricgas/EIProject/docs/InfraSourcePhase2FinalReport6AUG07.pdf>.

[23] Undergrounding Assessment Phase 3 Report, *Ex Ante cost and Benefit Modeling,* issued May 21, 2008, < http://www.cba.ufl.edu/purc/docs/initiatives_UndergroundingAssessment3.pdf>

Section II. Actual Distribution Service Reliability and Exclusions of Individual Utilities

Retail customers are affected by all outage events and momentary events regardless of where problems originate. For example, generation events and transmission events, while electrically remote from the distribution system serving a retail customer, impact the distribution service reliability experience of customers. This total service reliability experience is intended to be captured by the "actual" reliability data.

The actual reliability data includes two subsets of outage data: data on excludable events and data pertaining to normal day-to-day activities. Rule 25-6.0455(4), F.A.C., explicitly lists outage events that may be excluded:

(1) Planned service interruptions
(2) A storm named by the National Hurricane Center
(3) A tornado recorded by the National Weather Service
(4) Ice on lines
(5) A planned load management event
(6) Any electric generation or transmission event not governed by subsections 25-6.018(2) and (3), F.A.C.
(7) An extreme weather or fire event causing activation of the county emergency operation center

This section provides an overview of each IOU's actual 2007 performance data and focuses on the exclusions allowed by the rule. 2006 was the first year for which actual reliability data has been provided.

Florida Power & Light Company: Actual Data

Table 2-1 provides an overview of key FPL metrics: Customer Minutes of Interruption (CMI) and Customer Interruptions (CI) for 2007. Excludable outage events accounted for approximately 7% of service interruptions experienced by FPL's customers.

Table 2-1. FPL's 2007 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	**% of Actual**	**Value**	**% of Actual**
Reported Actual Data	366,940,414		5,814,648	
Documented Exclusions				
Named Storm Outages	12,562,221	3.42%	162,644	2.80%
Fires	48,890	0.01%	674	0.01%
Planned Outages	12,114,774	3.30%	115,527	1.99%
Tornadoes	11,862,598	3.23%	113,956	1.96%
Other	3,556,068	0.97%	43	0.00%
Reported Adjusted Data	326,795,863	89.06%	5,421,804	93.24%

FPL provided adequate support for its excludable event adjustments allowed by Rule 25-6.0455(4), F.A.C., for calendar year 2007.

Progress Energy Florida, Inc.: Actual Data

Table 2-2 provides an overview of PEF's CMI and CI figures for 2007. Excludable outage events accounted for approximately 37% of service interruptions experienced by PEF's customers.

Table 2-2. PEF's 2007 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	**% of Actual**	**Value**	**% of Actual**
Reported Actual Data	185,138,276		2,937,236	
Documented Exclusions				
Transmission- non weather	14,352,325	7.75%	383,227	13.05%
Severe Weather	30,275,798	16.35%	225,246	7.67%
Emergency Shutdowns	5,291,458	2.86%	345,790	11.77%
Prearranged & Dispatch Resolved	7,543,644	4.07%	147,183	5.01%
Reported Adjusted Data	127,675,051	68.96%	1,835,790	62.50%

PEF provided adequate support for its excludable event adjustments allowed by Rule 25-6.0455(4), F.A.C. for calendar year 2007.

Tampa Electric Company: Actual Data

Table 2-3 provides an overview of TECO's CMI and CI figures for 2007. Excludable outage events accounted for approximately 8% of service interruptions experienced by TECO's customers.

Table 2-3. TECO's 2007 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		**Customer Interruptions (CI)**	
	Value	**% of Actual**	**Value**	**% of Actual**
Reported Actual Data	55,464,320		746,535	
Documented Exclusions				
Severe Weather	3,124,639	5.63%	41,353	5.54%
Planned Outages	872,782	1.57%	21,702	2.91%
Reported Adjusted Data	51,466,899	92.79%	683,480	91.55%

TECO provided adequate support for its excludable event adjustments allowed by Rule 25-6.0455(4), F.A.C., for calendar year 2007.

Gulf Power Company: Actual Data

Table 2-4 provides an overview of Gulf's CMI and CI figures for 2007. Excludable outage events accounted for approximately 34% of service interruptions experienced by Gulf's customers.

Table 2-4. Gulf's 2007 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	% of Actual	Value	% of Actual
Reported Actual Data	66,347,522		764,928	
Documented Exclusions				
Transmission Events	3,819,531	5.76%	121,376	15.87%
Planned Outages	6,625,903	9.99%	123,819	16.19%
Tornado	2,529,434	3.81%	16,862	2.20%
Reported Adjusted Data	53,372,654	80.44%	502,871	65.74%

Gulf provided adequate support for its excludable event adjustments allowed by Rule 25-6.0455(4), F.A.C., for calendar year 2007.

Florida Public Utilities Company: Actual Data

In 2007 FPUC did not exclude any events from its system data. FPUC notes that it did not experience any major storms or hurricanes during the 2007 reporting period, and thus no adjustments were needed.

Section III. Adjusted Distribution Service Reliability Review of Individual Utilities

Review of the adjusted distribution reliability metrics provides insight into potential trends in a utility's daily practices and maintenance of its distribution facilities. This section of the review is based on each utility's reported adjusted data.

Florida Power & Light Company: Adjusted Data

Figure 3-1 shows the maximum, average, and minimum adjusted SAIDI recorded across FPL's system. FPL's average SAIDI improved slightly from 2006 to 2007, declining by one minute from 74 to 73 (1%).

Figure 3-1. SAIDI across FPL's Seventeen Regions (Adjusted)

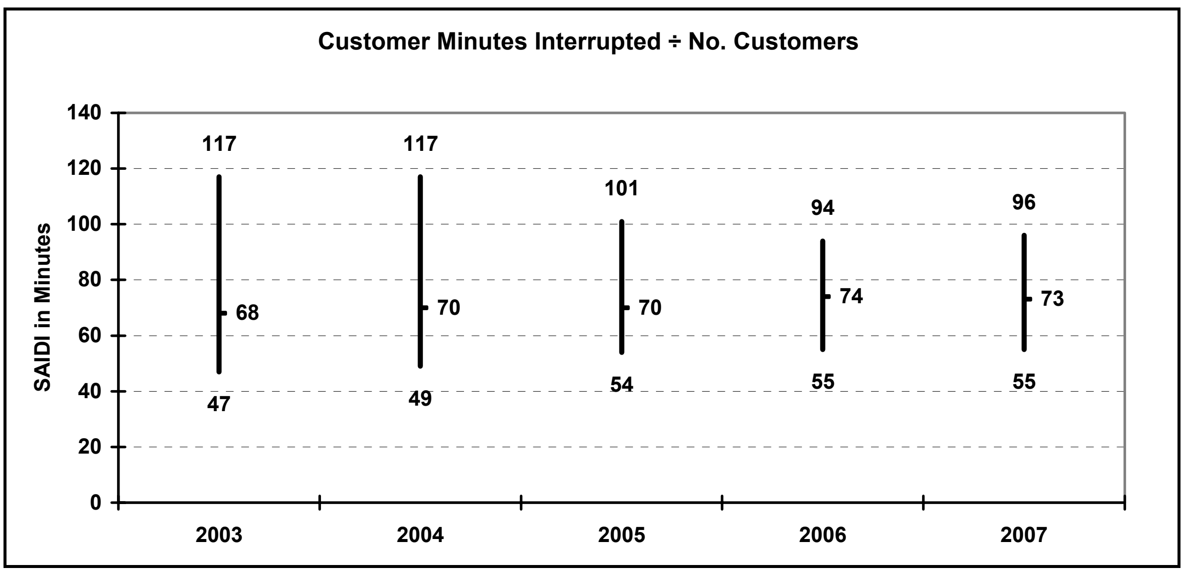


Figure 3-2 shows the maximum, average, and minimum adjusted SAIFI across FPL's system. FPL's SAIFI fell from 1.29 in 2006, to 1.21 in 2007, indicating a 6% improvement.

Figure 3-2. SAIFI across FPL's Seventeen Regions (Adjusted)

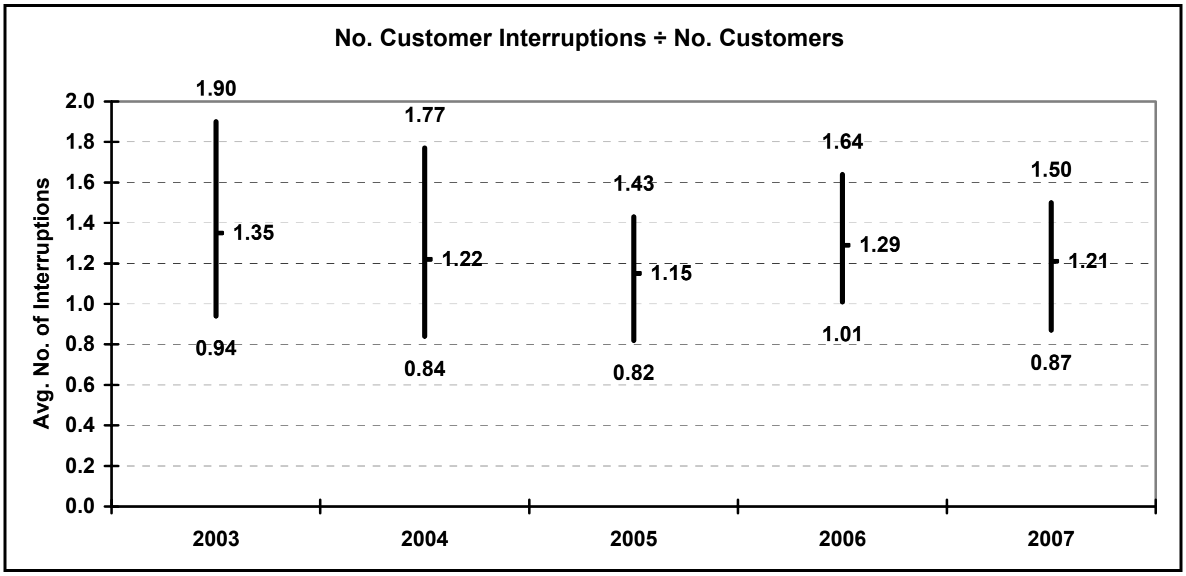
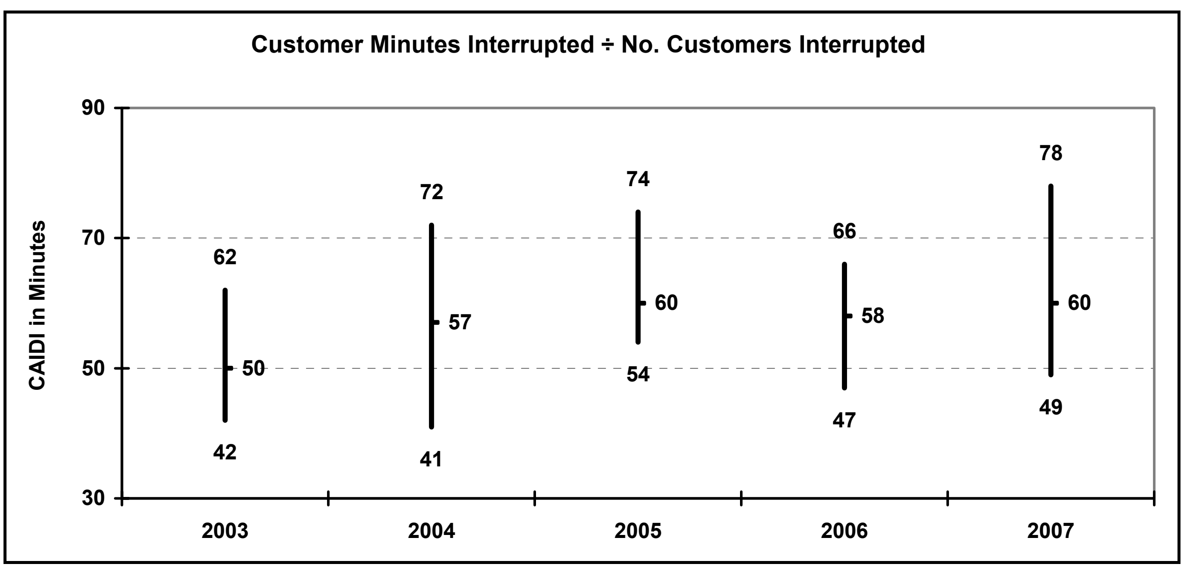


Figure 3-3 shows the maximum, average, and minimum CAIDI across FPL's system. FPL's average CAIDI increased from 58 minutes in 2006 to 60 minutes in 2007, a 3% decrease in CAIDI measured reliability.

Figure 3-3. CAIDI across FPL's Seventeen Regions (Adjusted)



The average length of time FPL spends recovering from outage events, excluding hurricanes and other extreme outage events, is represented by its L-Bar index shown in Figure 3-4. FPL's average service restoration length increased from 205 minutes in 2006 to 211 minutes in 2007 (3%). Many factors can contribute to increases in L-Bar, including increased numbers of underground outages, the cause and location of the outage event, the amount of distribution facilities needing replacement or repair, and the number of available trained and equipped personnel. Frequent outage problems experienced by a subset of customers indicate a need for improvement.

Figure 3-4. FPL's Average Duration of Outages (Adjusted)

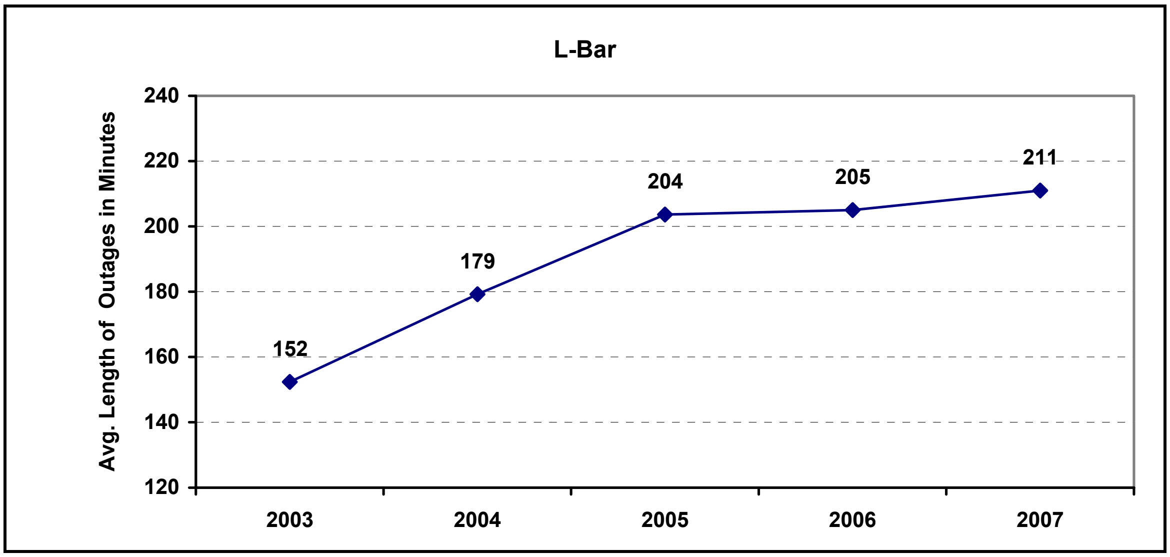


Figure 3-5 shows the maximum, average, and minimum adjusted MAIFIe recorded across FPL's system. Isolated momentary events also occur on segments of the distribution circuit remote from the substation where the MAIFIe data is measured. These remote momentary events often affect a small group of customers or even just one customer. Such outage problems can be masked by the previously discussed indices of SAIDI, SAIFI, CAIDI, and L-Bar. FPL's average MAIFIe increased from 11.1 to 11.4 (3%) from 2006 to 2007.

Figure 3-5. MAIFIe across FPL's Seventeen Regions (Adjusted)

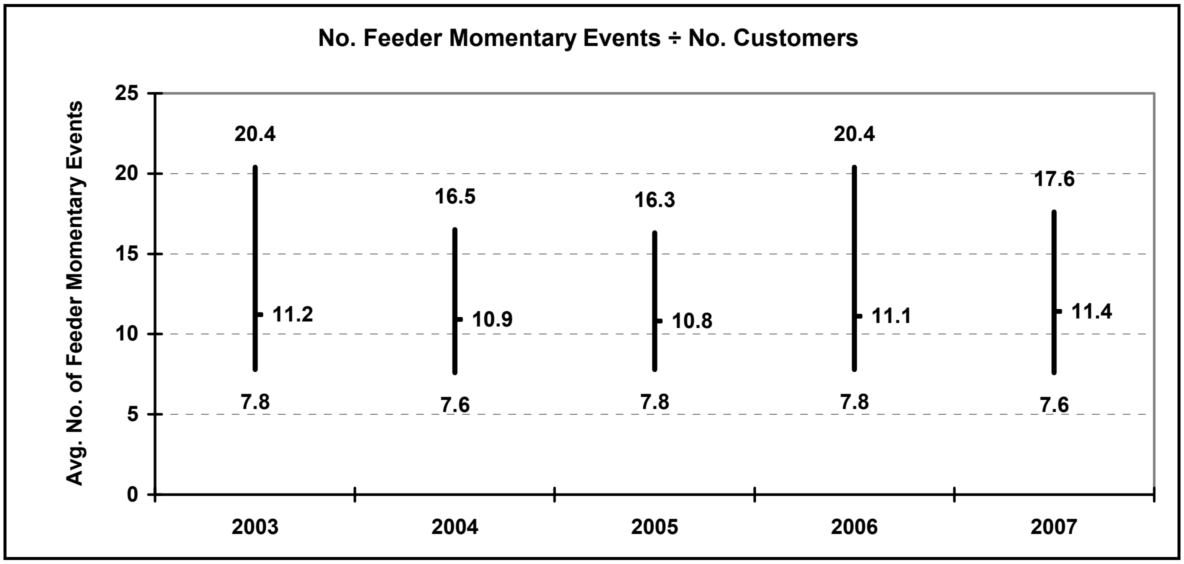
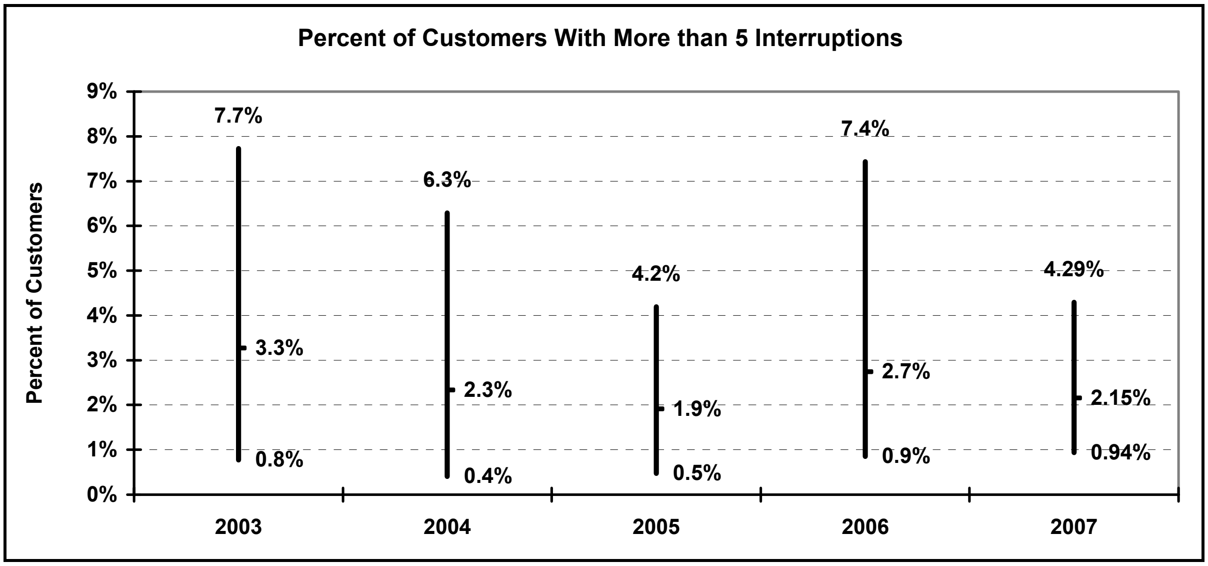


Figure 3-6 displays the maximum, average, and minimum adjusted CEMI5. FPL's average CEMI5 shows improvement from 2006 to 2007, falling from 2.7%, to 2.15% (20%).

Figure 3-6. CEMI5 across FPL's Seventeen Regions (Adjusted)



The Three Percent Feeder Report is a listing of the top three percent of feeders with the most feeder outage events. The fraction of multiple occurrences, Figure 3-7, is calculated from the number of recurrences divided by the number of feeders reported on a three-year and five-year basis. Reporting the fraction of multiple outage occurrences on a three-year and a five-year basis allows a more rigorous analysis of trend patterns. As shown, FPL data indicates a general decline in outage reoccurrences of feeders that appeared on its Three Percent Feeder Report, indicating improved feeder reliability.

Figure 3-7. FPL's Three Percent Feeder Report (Adjusted)

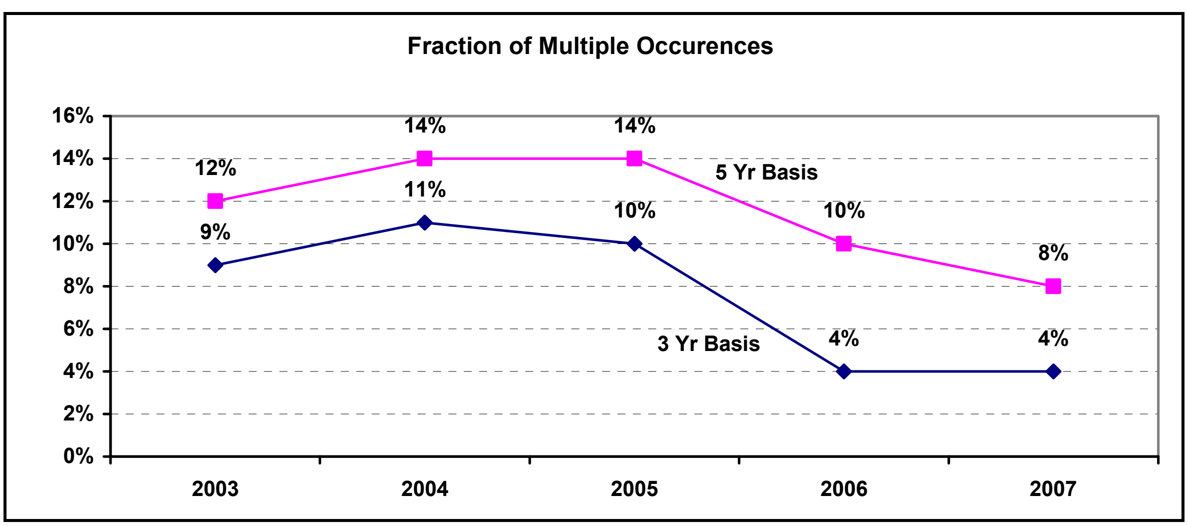
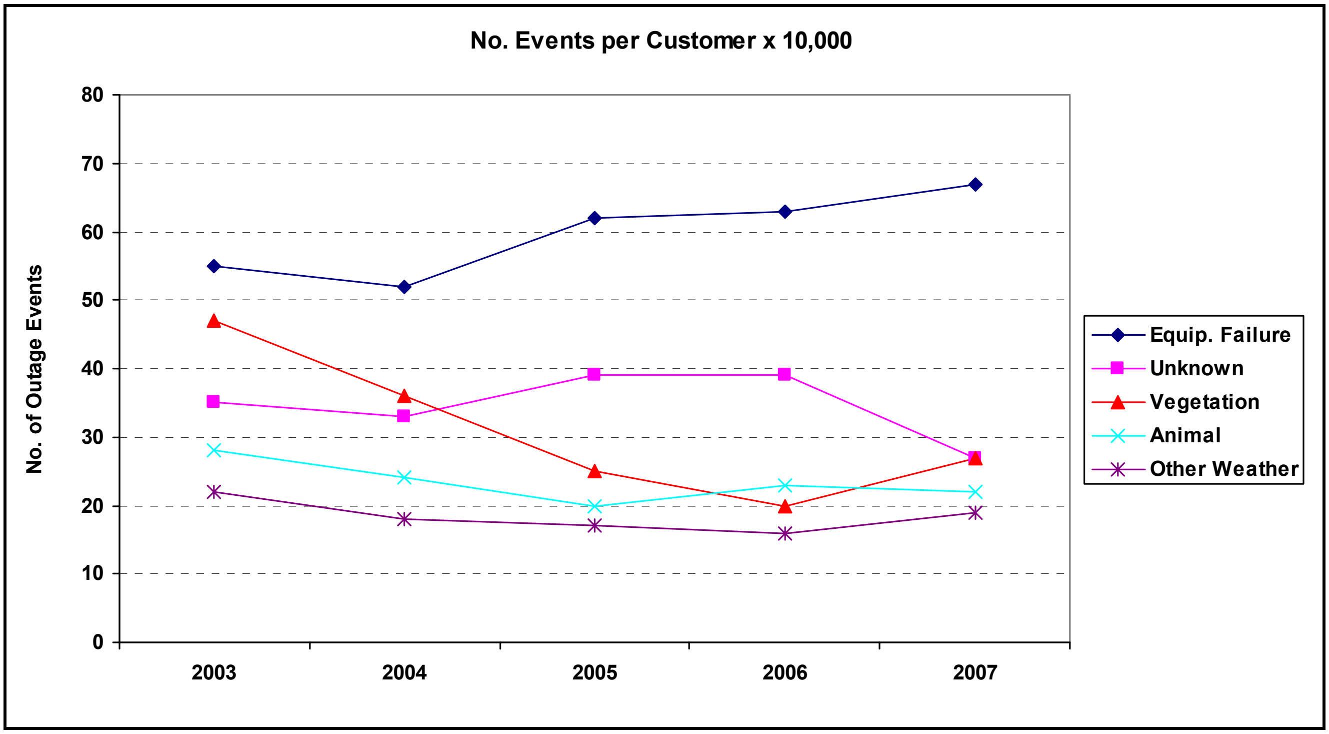


Figure 3-8 shows the top five causes of outage events on FPL's distribution system per 10,000 customers. The figure is based on FPL's adjusted data of the top ten causes of outage events and represents most of the outage events that occurred between December 31, 2003, and January 1, 2008.

Figure 3-8. FPL's Top Five Outage Causes (Adjusted)



The review of FPL's supporting data, adjusted for customer growth, shows a decrease in the total number of outage events over the five-year period 2003 thru 2007.

Observations: FPL's Adjusted Data

In 2007, FPL's overall service reliability yields mixed results. FPL's SAIDI and SAIFI indicies show improvement over 2006. However, FPL's 2007 CAIDI, L-Bar, and MAIFI indices demonstrate decreased reliability relative to 2006.

Progress Energy Florida, Inc.: Adjusted Data

Figure 3-9 shows the maximum, average, and minimum adjusted SAIDI recorded across PEF's system. PEF's average SAIDI increased from 75 minutes in 2006 to 78 in 2007 (4%).

Figure 3-9. SAIDI across PEF's Four Regions (Adjusted)

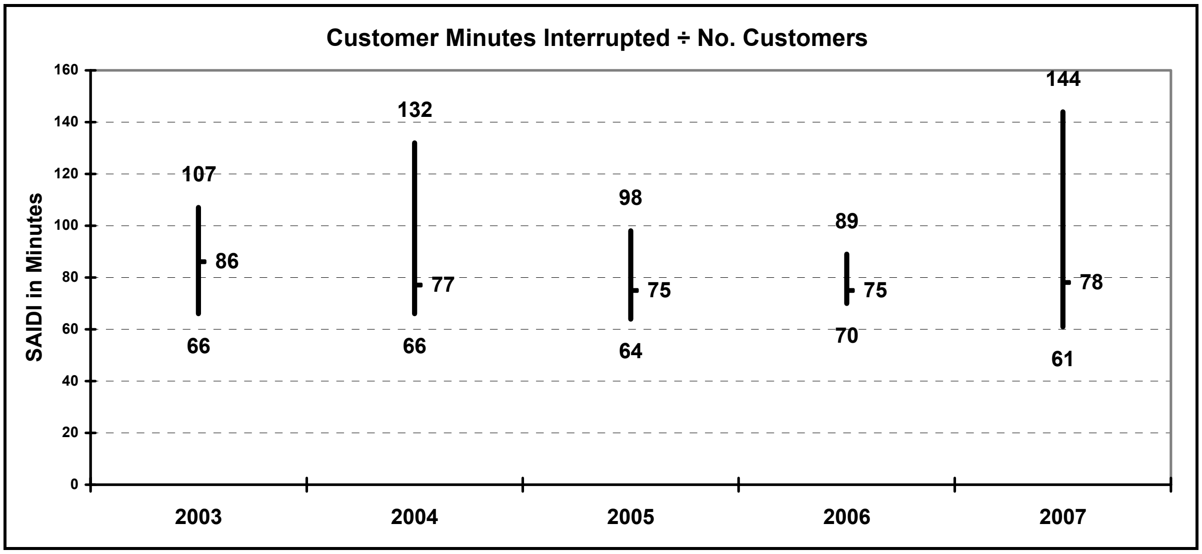


Figure 3-10 shows the maximum, average, and minimum adjusted SAIFI across PEF's system. PEF's average SAIFI increased from 1.09 in 2006 to 1.13 in 2007 (4%).

Figure 3-10. SAIFI across PEF's Four Regions (Adjusted)

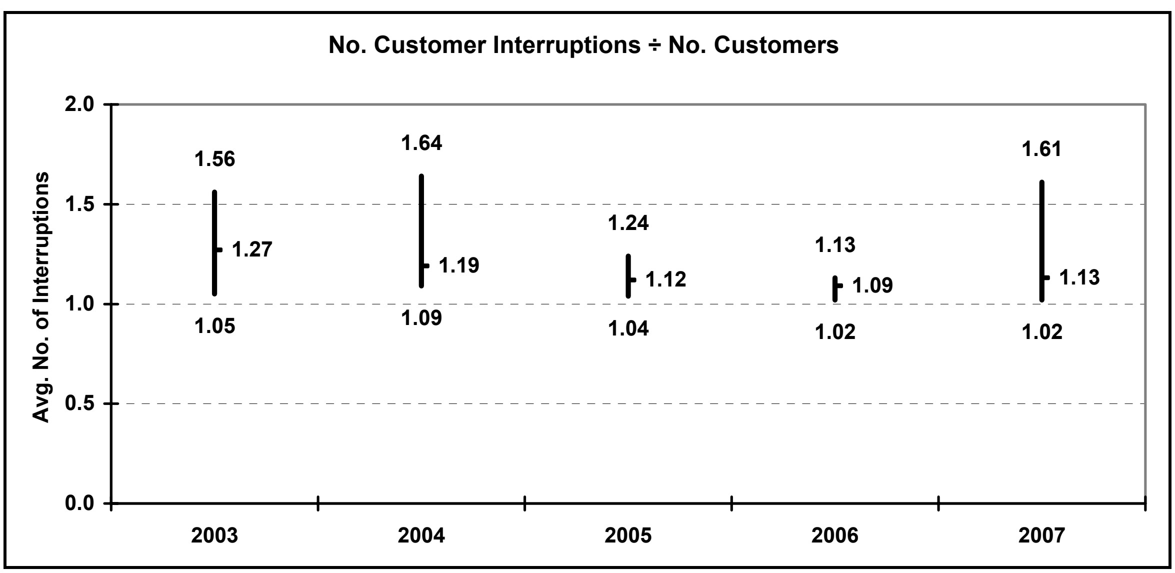
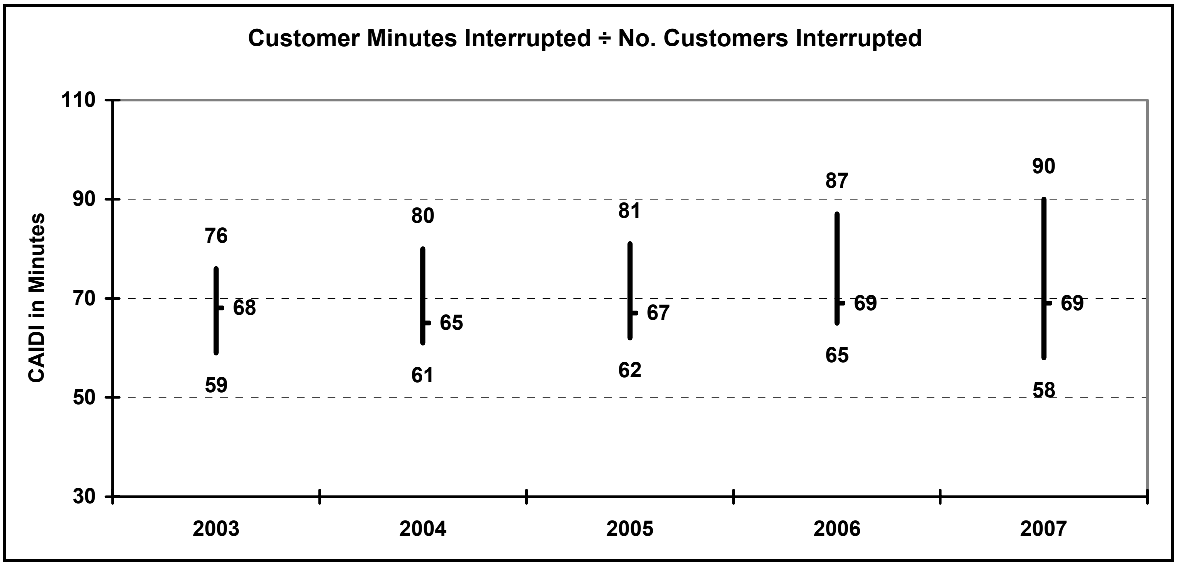


Figure 3-11 represents PEF's adjusted CAIDI. PEF's average CAIDI remained unchanged from 2006 to 2007, holding at 69 minutes.

Figure 3-11. CAIDI across PEF's Four Regions (Adjusted)



The average length of time PEF spends recovering from outage events, excluding hurricanes and other extreme outage events, is the index L-Bar shown in Figure 3-12. PEF's average service restoration length increased from 121 minutes in 2006 to 122 in 2007 (<1%).

Figure 3-12. PEF's Average Duration of Outages (Adjusted)

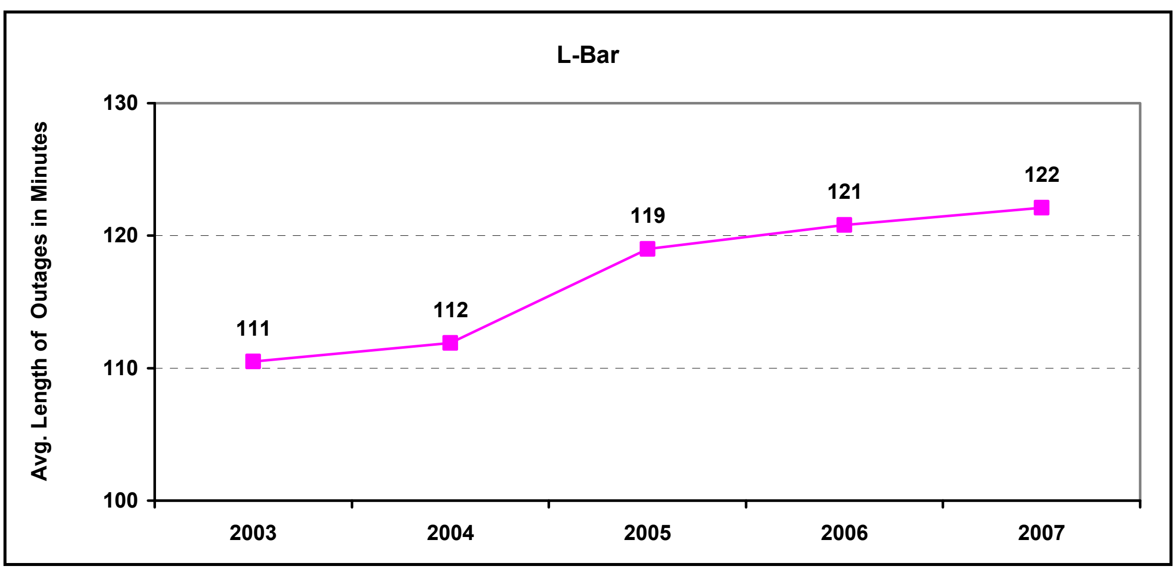


Figure 3-13 shows the maximum, average, and minimum adjusted MAIFIe recorded across PEF's system. PEF's average MAIFIe increased from 10.8 to 11.3 (5%) from 2006 to 2007.

Figure 3-13. MAIFIe across PEF's Four Regions (Adjusted)

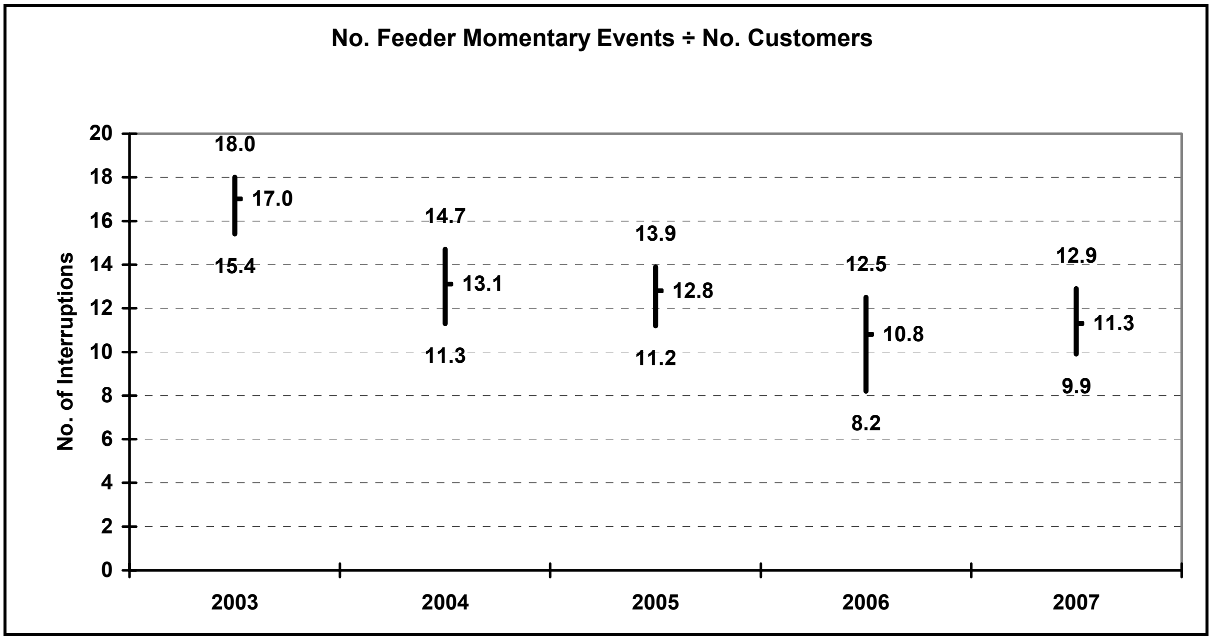
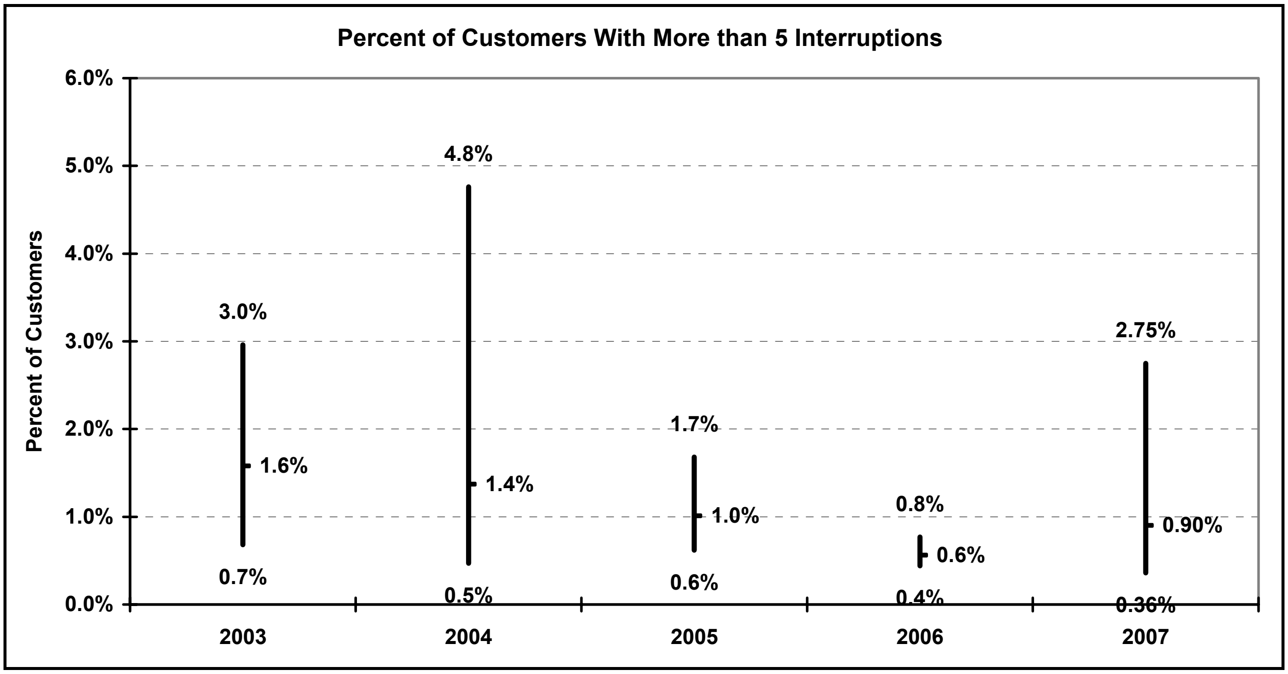


Figure 3-14 shows the maximum, average, and minimum adjusted CEMI5. PEF's 2007 reliability data demonstrate an increase in the average percent of customers with more than 5 service interruptions, from 0.6% to 0.9%.

Figure 3-14. CEMI5 across PEF's Four Regions (Adjusted)



The Three Percent Feeder Report lists the top three percent of feeders with the most feeder outage events. The fraction of multiple occurrences is calculated from the number of recurrences, divided by the number of feeders reported. Figure 3-15 shows the fraction of multiple occurrences of feeders using a three-year and five-year basis.

Figure 3-15. PEF's Three Percent Feeder Report (Adjusted)

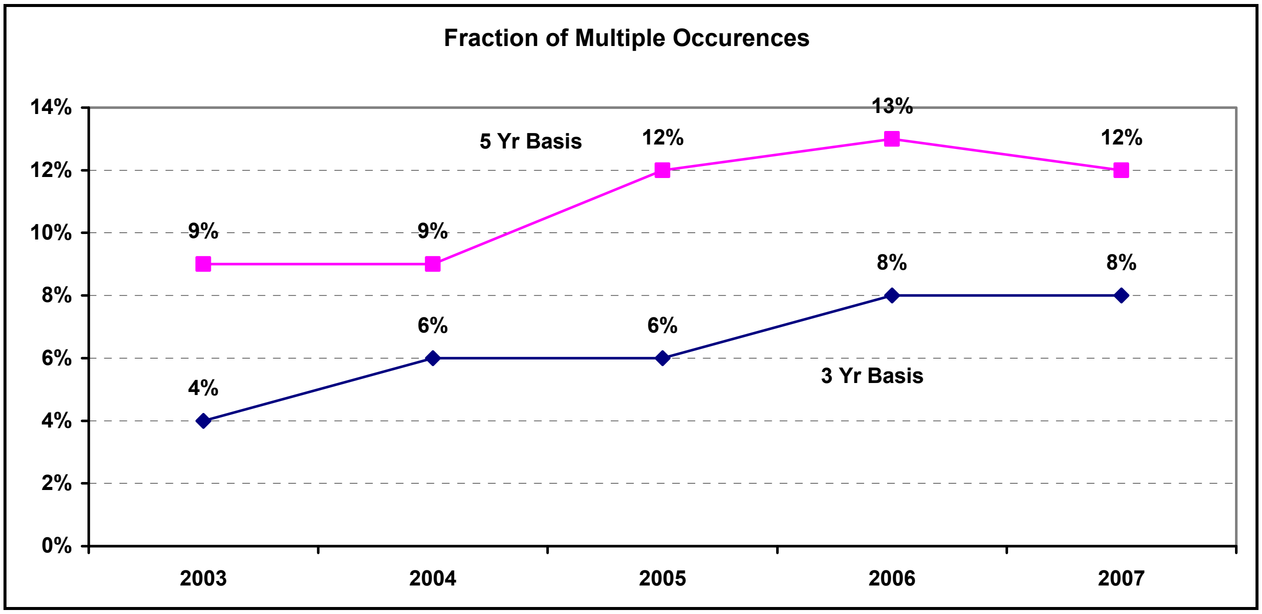
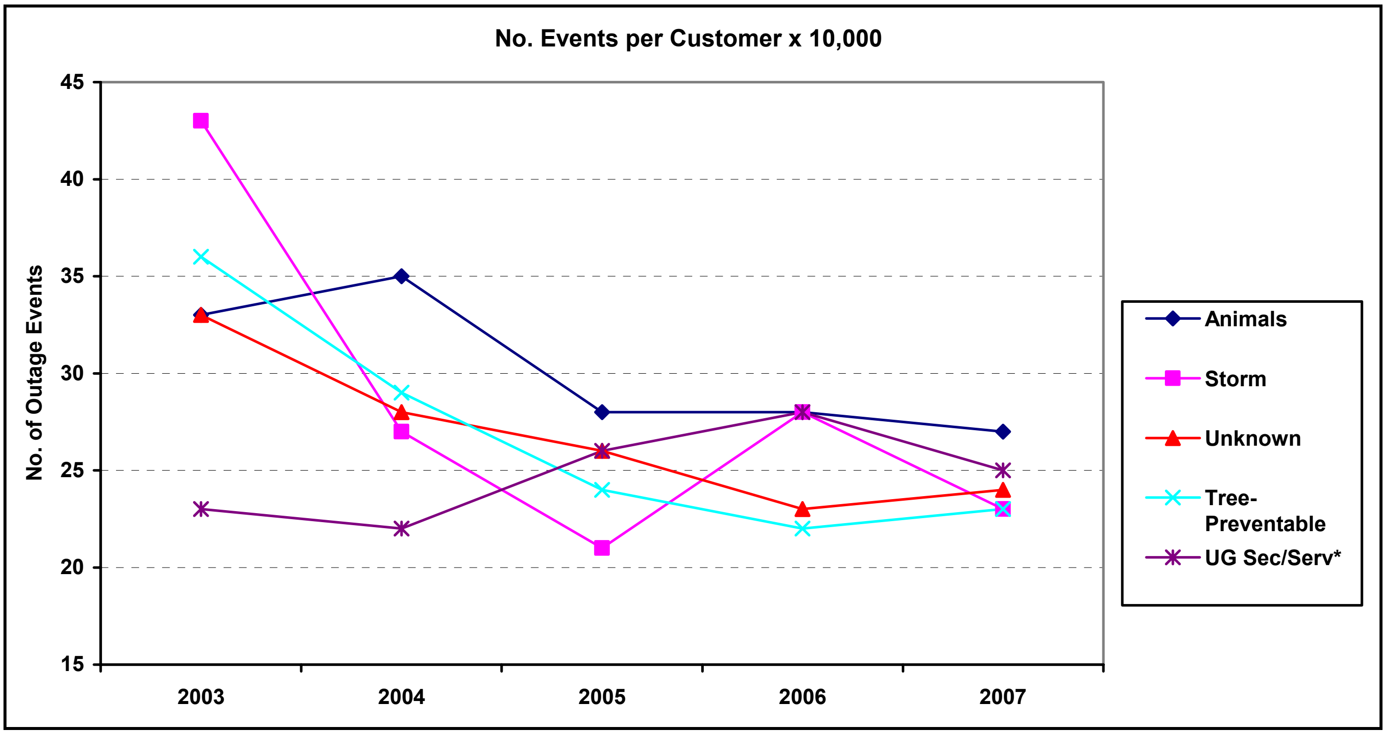


Figure 3-16 shows the top five causes of outage events on PEF's distribution system per 10,000 customers. The figure is based on PEF's adjusted data of the top ten causes of outage events. PEF uses its "Tree-Preventable" code to denote instances where it believes additional tree trimming could have avoided the outage event.

Figure 3-16. PEF's Top Five Outage Causes (Adjusted)



* Underground Secondary/Service cause description is used when outages are caused by a fault in the underground secondary or service cables. Secondary cable is underground cable located between a transformer and a pedestal. Service underground cable is underground cable located between a pedestal or transformer and the meter.

Observations: PEF's Adjusted Data

In general, PEF's 2007 overall service reliabilty, as measured by SAIDI, SAIFI, MAIFe and L-Bar, has declined slighlty from its 2006 levels, while PEF's average CAIDI has remained unchanged. On balance, PEF's system reliability was relatively constant.

Tampa Electric Company: Adjusted Data

Figure 3-17 shows the maximum, average, and minimum adjusted SAIDI recorded across TECO's system. TECO's average SAIDI increased from 69 minutes in 2006 to 77 minutes in 2007 (12%).

Figure 3-17. SAIDI across TECO's Seven Regions (Adjusted)

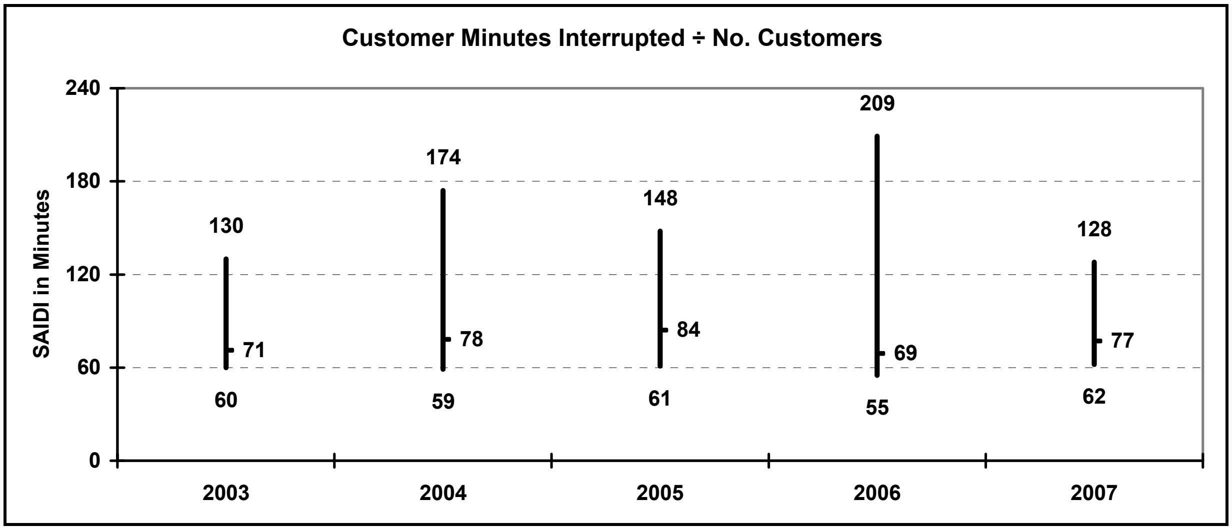


Figure 3-18 graphs the maximum, average, and minimum adjusted SAIFI across TECO's system. TECO's average adjusted SAIFI increased from 0.89 interruptions per customer in 2006, to 1.02 interruptions per customer in 2007 (15%).

Figure 3-18. SAIFI across TECO's Seven Regions (Adjusted)

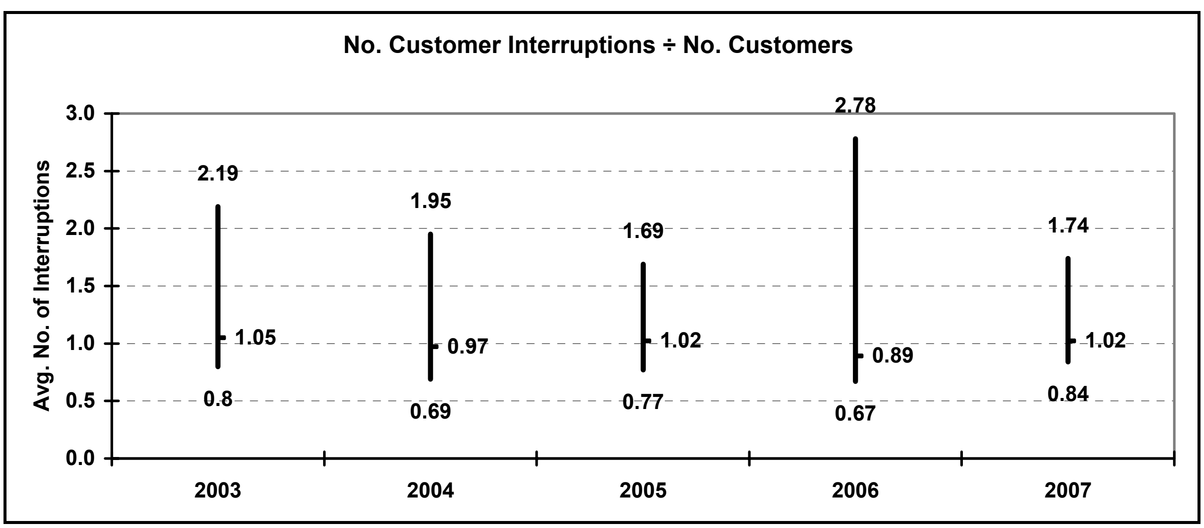
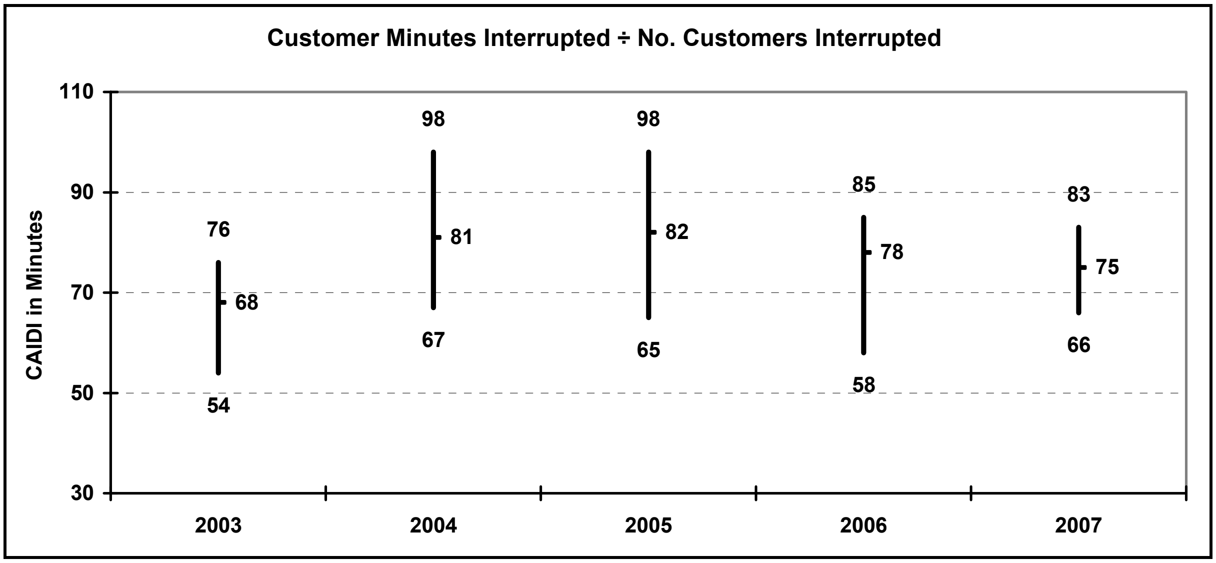


Figure 3-19 shows the maximum, average, and minimum adjusted CAIDI across TECO's system. TECO's average CAIDI improved by 3 minutes (4%) in the review period, moving from 78 minutes in 2006 to 75 minutes in 2007.

Figure 3-19. CAIDI across TECO's Seven Regions (Adjusted)



The average length of time TECO spends recovering from outage events, excluding hurricanes and other extreme outage events, is the index L-Bar shown in Figure 3-20. TECO's L-Bar decreased slightly, from 163 minutes in 2007 to 162 minutes in 2007 (<1%).

Figure 3-20. TECO's Average Duration of Outages (Adjusted)

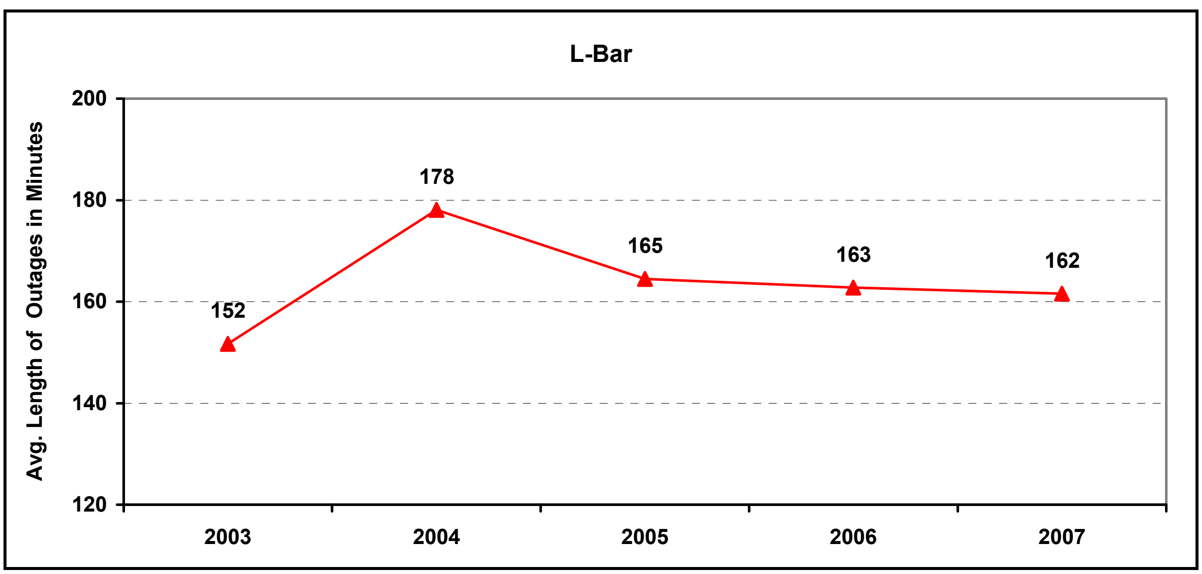


Figure 3-21 shows the maximum, average, and minimum adjusted MAIFIe recorded across TECO's system. TECO's average adjusted system MAIFIe increased from 12.8 in 2006 to 13.9 in 2007 (9%).

Figure 3-21. MAIFIe across TECO's Regions (Adjusted)

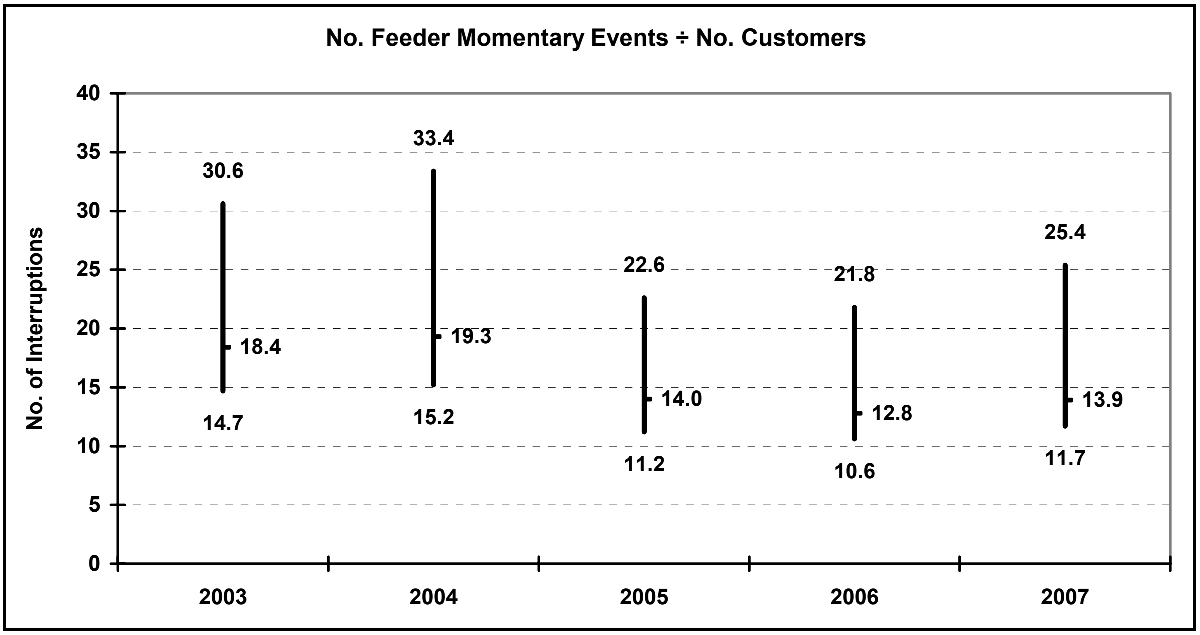
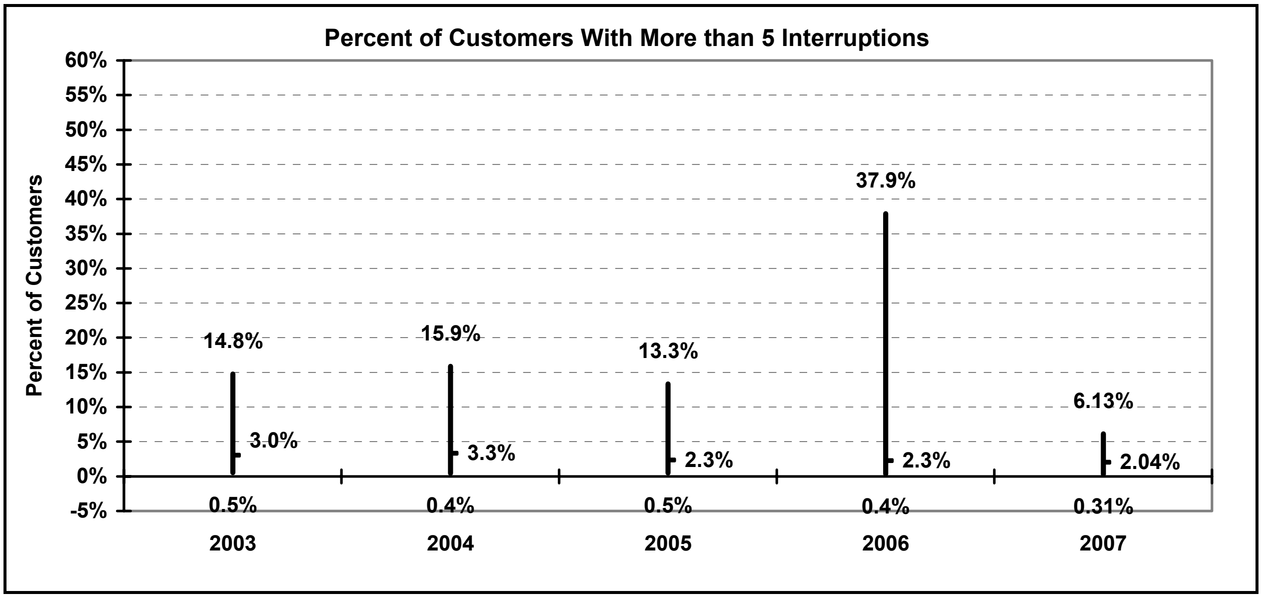


Figure 3-22 shows TECO's maximum, average, and minimum adjusted system CEMI5. TECO's average percent of customers experiencing more than five interruptions decreased from 2.30% in 2006, to 2.04% in 2007 (11%).

Figure 3-22. CEMI5 across TECO's Seven Regions (Adjusted)



The Three Percent Feeder Report lists the top three percent of feeders with the most feeder outage events. The fraction of multiple occurrences is calculated from the number of recurrences, divided by the number of feeders reported. Figure 3-23 shows the fraction of multiple occurrences of feeders using a three-year and five-year basis.

Figure 3-23. TECO's Three Percent Feeder Report (Adjusted)

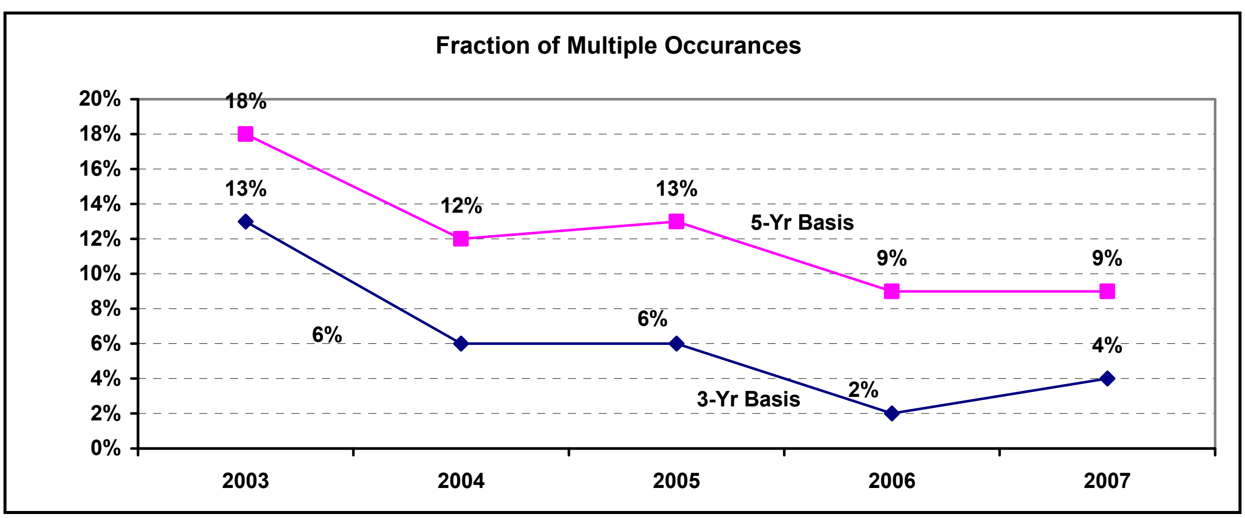
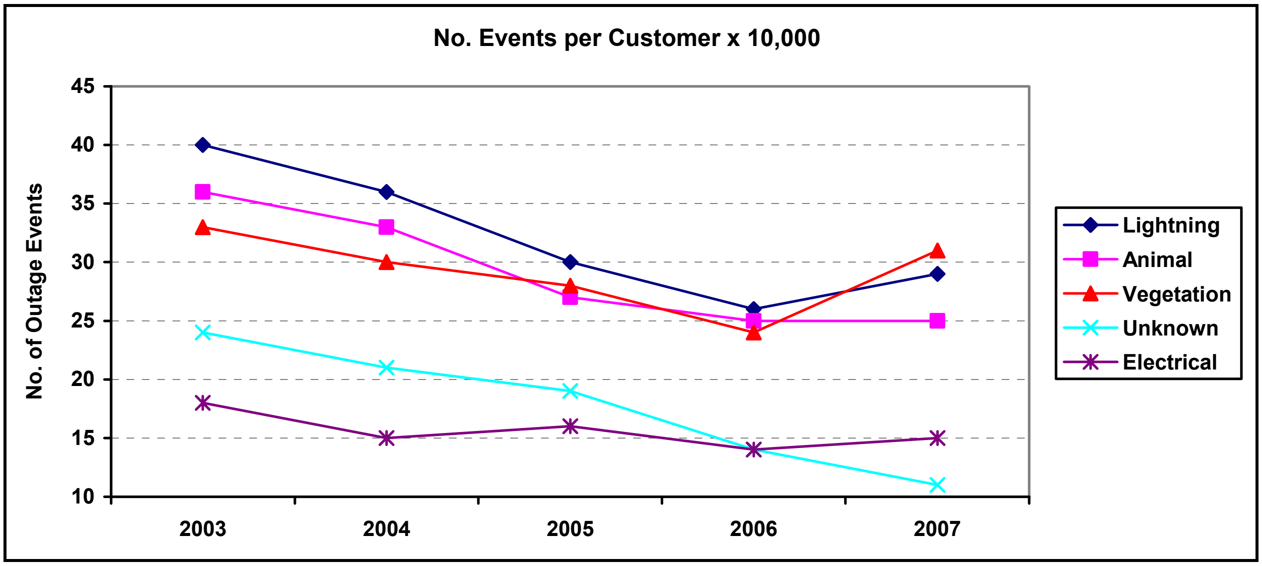


Figure 3-24 shows the top 5 causes of outage events on TECO's distribution system per 10,000 customers. The figure is based on TECO's adjusted data of the top ten causes of outage events.

Figure 3-24. TECO's Top Five Outage Causes (Adjusted)



Observations: TECO's Adjusted Data

TECO's overall 2007 service reliability measures yield mixed results. TECO's adjusted L-Bar and CAIDI index indicate improvement over 2006. However, TECO's data show a decline in reliability as measured by SAIDI, SAIFI, and MAIFe indicies.

Gulf Power Company: Adjusted Data

Figure 3-25 shows the maximum, average, and minimum adjusted SAIDI recorded across Gulf's system. Gulf previously provided two explanations for the significant increase in its SAIDI in 2006. First, Gulf cites lingering effects from the 2004 and 2005 hurricane seasons. Second, Gulf notes that the data reflects several adverse weather events that were not excluded because they were not documented as tornadoes or named weather systems. Gulf's 2007 adjusted data suggest a significant improvement in its system outage frequency and durations from 2006. Gulf's average adjusted SAIDI decreased by 80 minutes per customer, falling from 205 minutes in 2006 to 125 minutes in 2007 (39%).

Figure 3-25. SAIDI across Gulf's Three Regions (Adjusted)

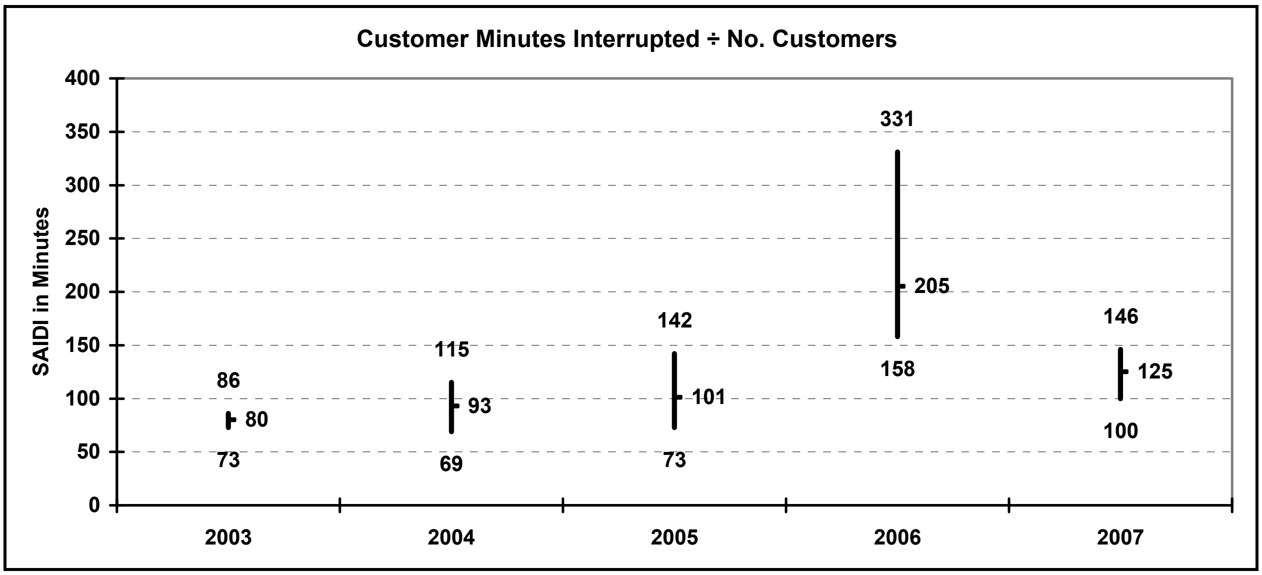


Figure 3-26 shows the maximum, average, and minimum adjusted SAIFI across Gulf's system. Gulf's average adjusted SAIFI decreased from 1.28 interruptions per customer in 2006, to 1.18 interruptions per customer in 2007 (8%).

Figure 3-26. SAIFI across Gulf's Three Regions (Adjusted)

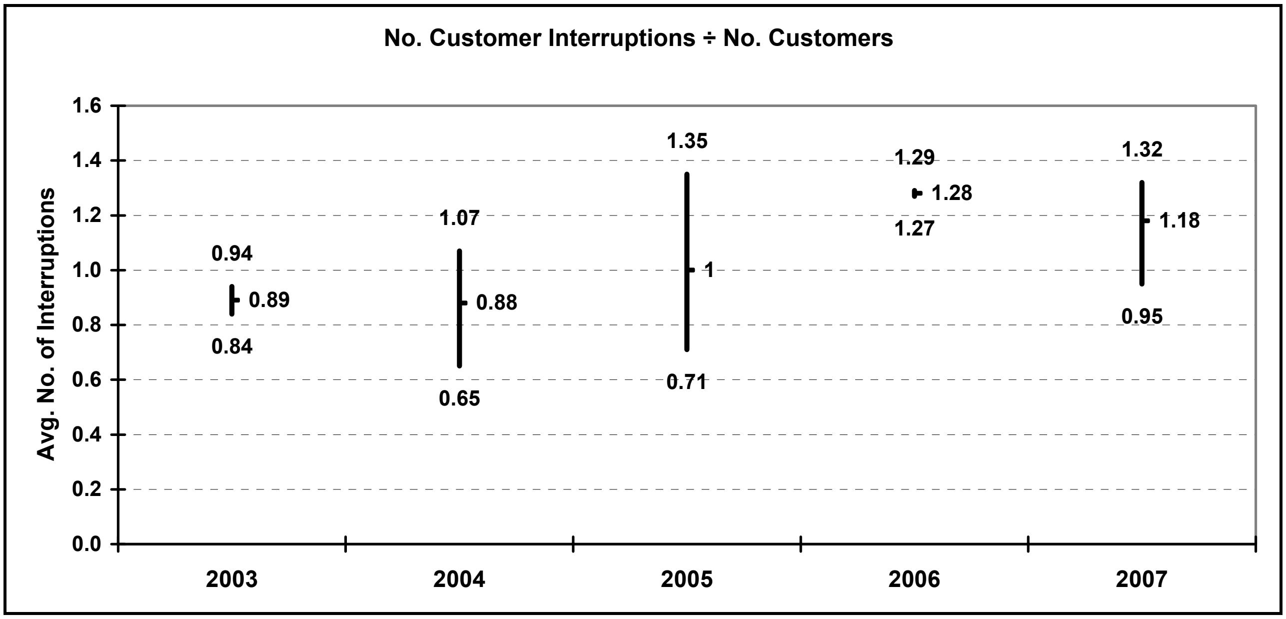
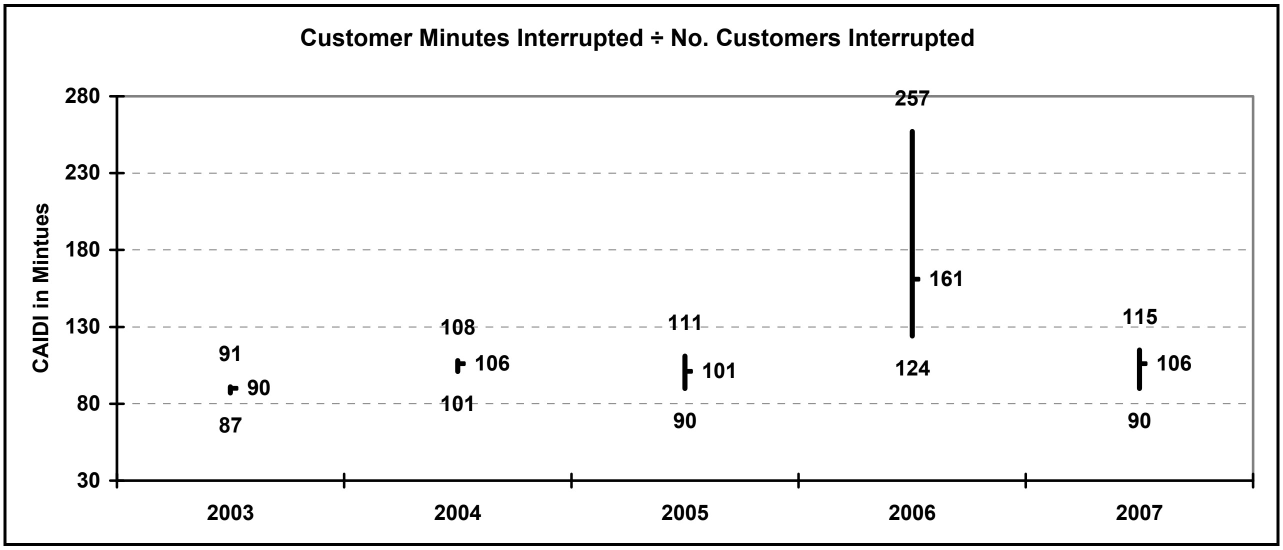


Figure 3-27 shows the maximum, average, and minimum adjusted CAIDI across Gulf's system. Gulf's average adjusted CAIDI improved by 55 minutes (34%) in the review period, moving from 161 minutes in 2006, to 106 in 2007.

Figure 3-27. CAIDI across Gulf's Three Regions (Adjusted)



The average length of time Gulf spends recovering from outage events, excluding hurricanes and other outage events, is the index L-Bar shown in Figure 3-28. Gulf's L-Bar also decreased significantly in this review period, from 170 minutes in 2006 to 132 minutes in 2007 (22%).

Figure 3-28. Gulf's Average Duration of Outages (Adjusted)

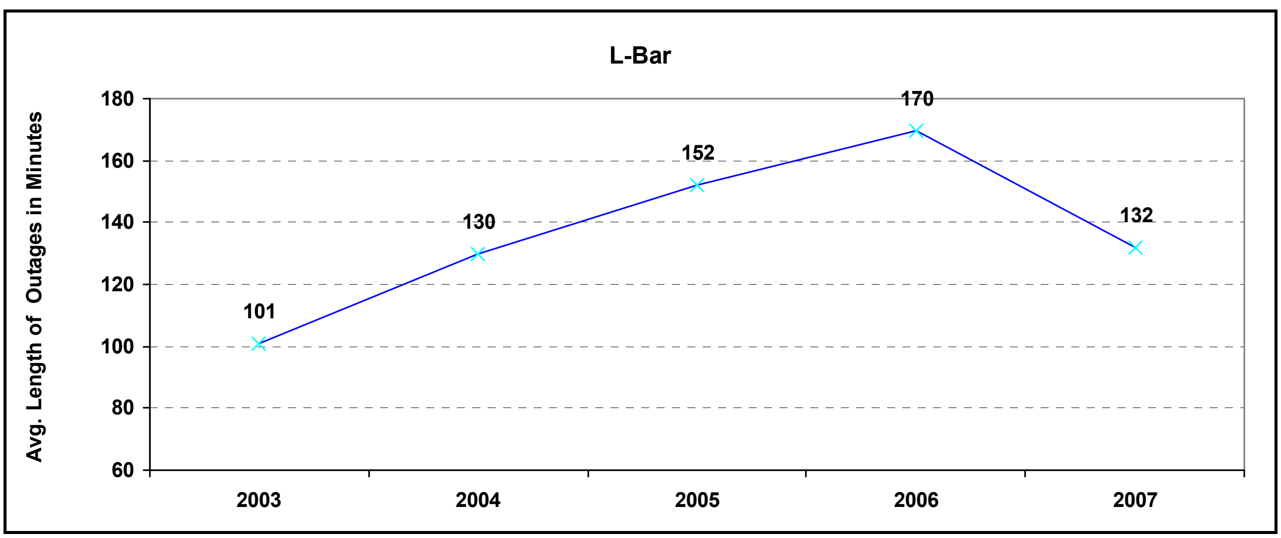


Figure 3-29 is the maximum, average, and minimum adjusted MAIFIe recorded across Gulf's system. Gulf's average MAIFIe fell from 8.2 in 2006, to 6.7 in 2007 (18%).

Figure 3-29. MAIFIe across Gulf's Three Regions (Adjusted)

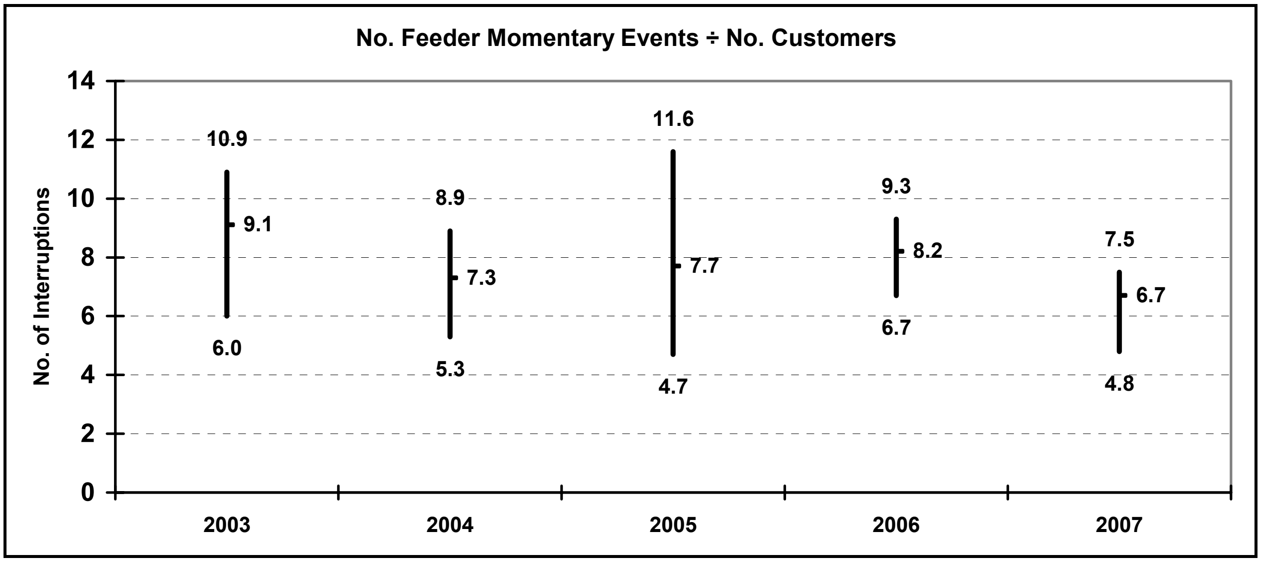
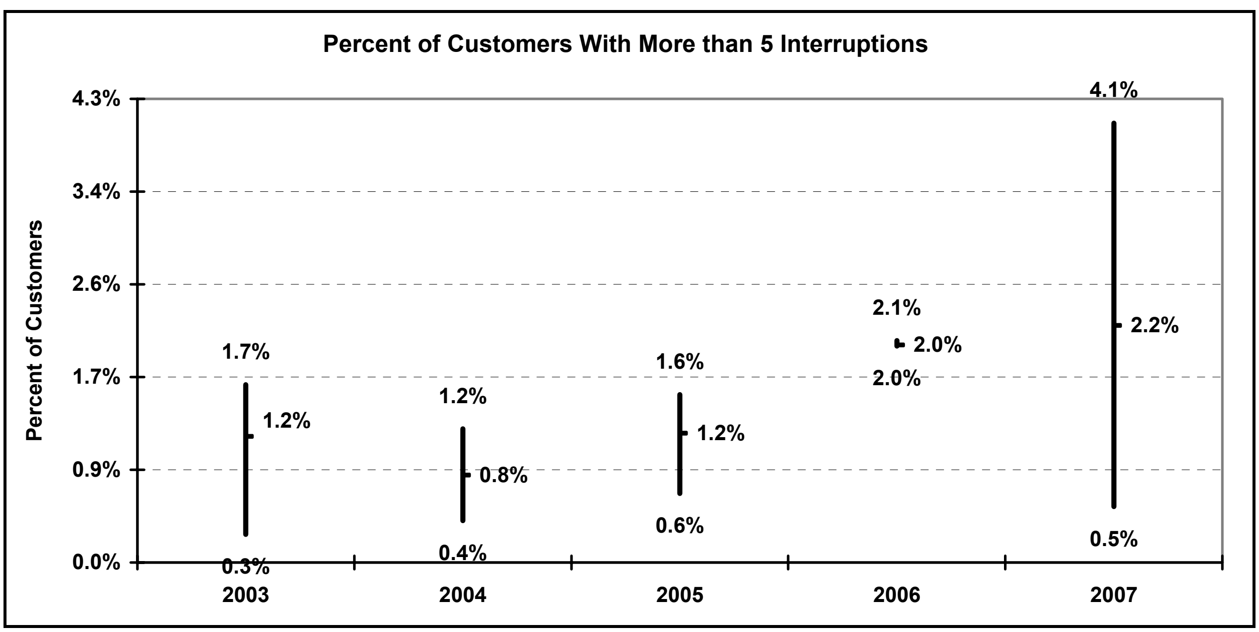


Figure 3-30 shows Gulf's maximum, average, and minimum adjusted CEMI5. Gulf's 2007 average adjusted CEMI5 increased slightly to 2.2%, up from 2.0% in 2006.

Figure 3-30. CEMI5 across Gulf's Three Regions (Adjusted)



The Three Percent Feeder Report lists the top three percent of feeders with the most feeder outage events. The fraction of multiple occurrences is calculated from the number of recurrences, divided by the number of feeders reported. Figure 3-31 shows the fraction of multiple occurrences of feeders using a three-year and-five year basis.

Figure 3-31. Gulf's Three Percent Feeder Report (Adjusted)

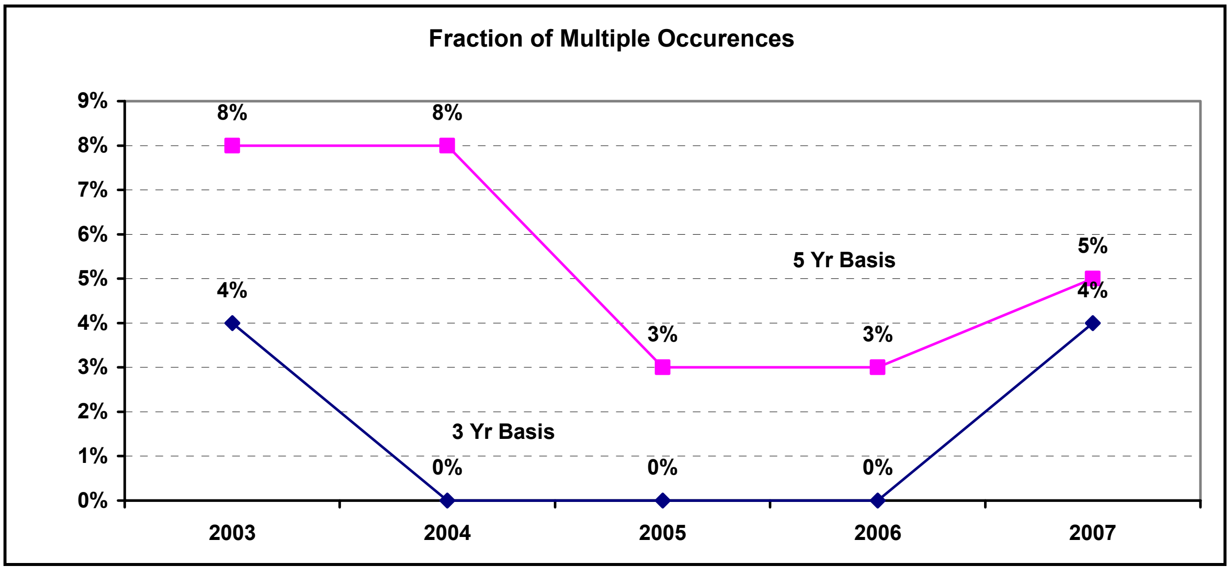
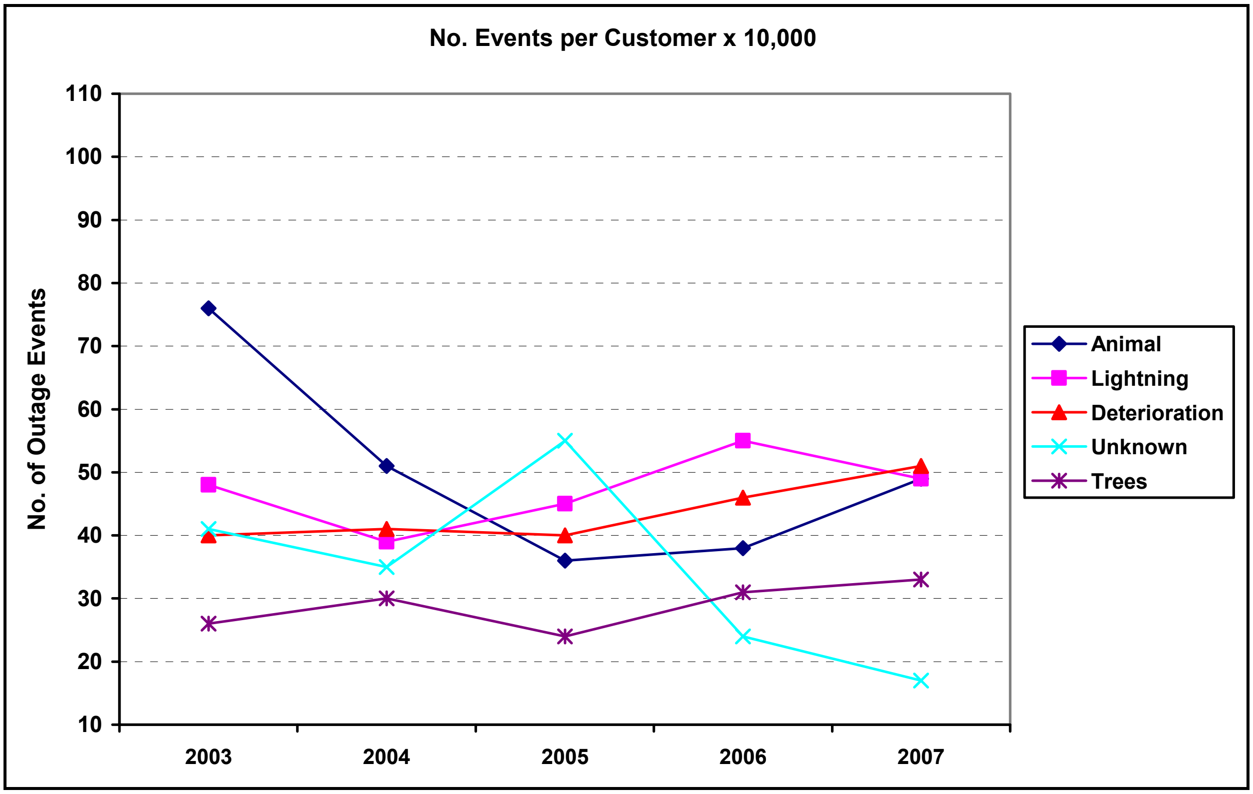


Figure 3-32 details the top 5 outage event causes on Gulf's distribution system per 10,000 customers. The figure is based on Gulf's adjusted data of the top ten causes of outage events.

Figure 3-32. Gulf's Top Five Outage Causes (Adjusted)



Observations: Gulf's Adjusted Data

Gulf's overall service reliabilty, as measured by SAIDI, SAIFI, MAIFe, CAIDI and L-Bar, demonstrate improved system reliability over the annual review period. However, Gulf's 2007 adjusted CEMI5 increased slightly, meaning the number of customers experiencing more than five interruptions annually rose.

Florida Public Utilities Company: Adjusted Data

Figure 3-33 is the maximum, average, and minimum adjusted SAIDI recorded across FPUC's system. FPUC's average adjusted SAIDI improved significantly, from 154 minutes in 2006 to 78 minutes in 2007, a 49% decrease.

Figure 3-33. SAIDI across FPUC's Two Regions (Adjusted)

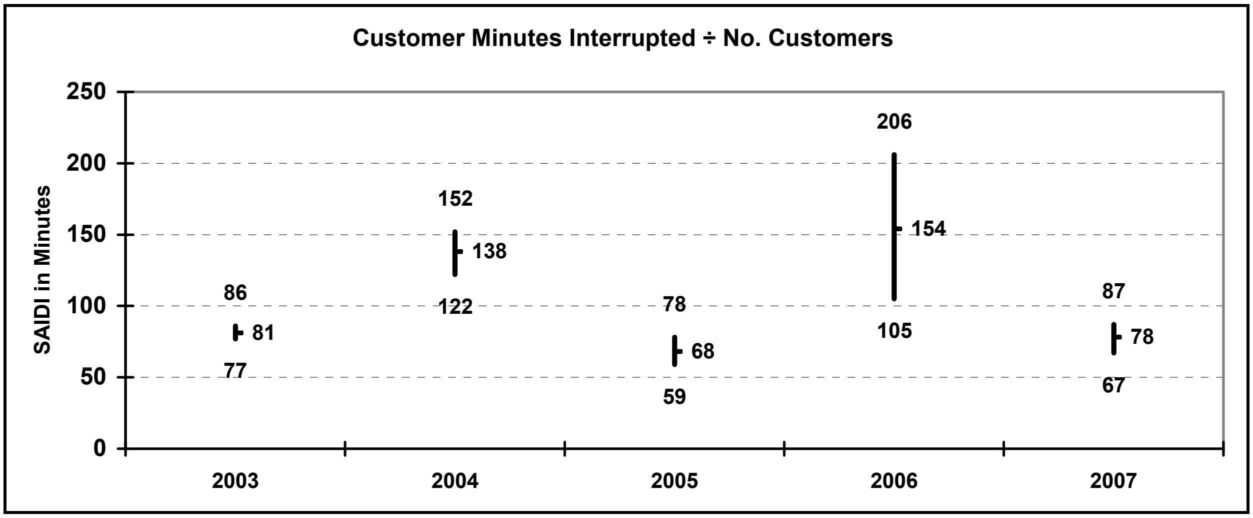


Figure 3-34 shows the maximum, average, and minimum adjusted SAIFI across FPUC's system. FPUC's average SAIFI fell from 1.43 in 2006 to 1.12 in 2007, a 22% improvement.

Figure 3-34. SAIFI across FPUC's Two Regions (Adjusted)

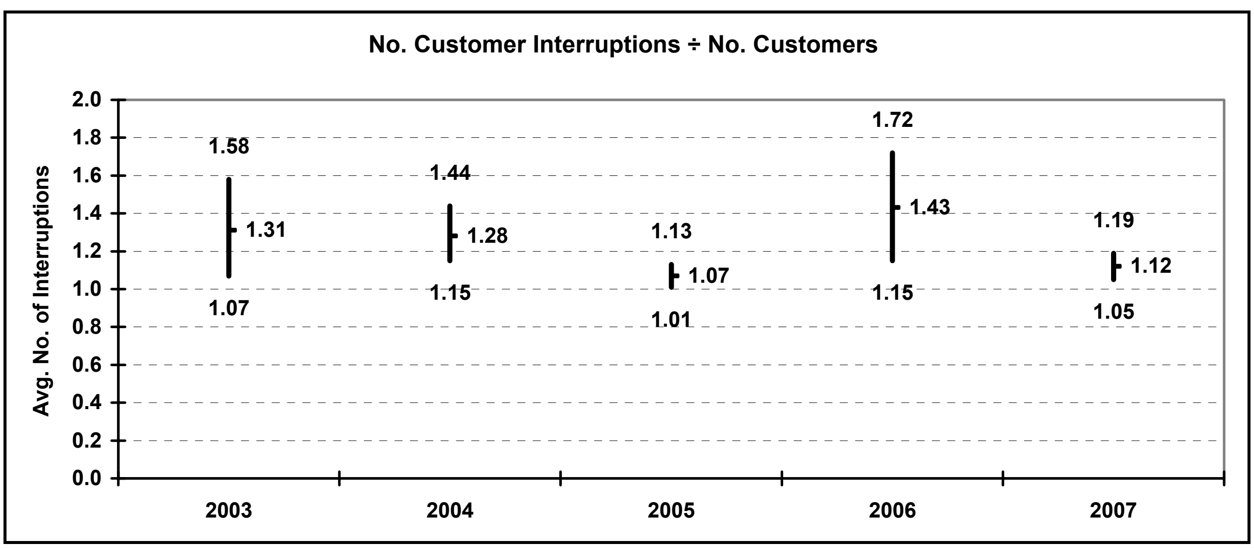
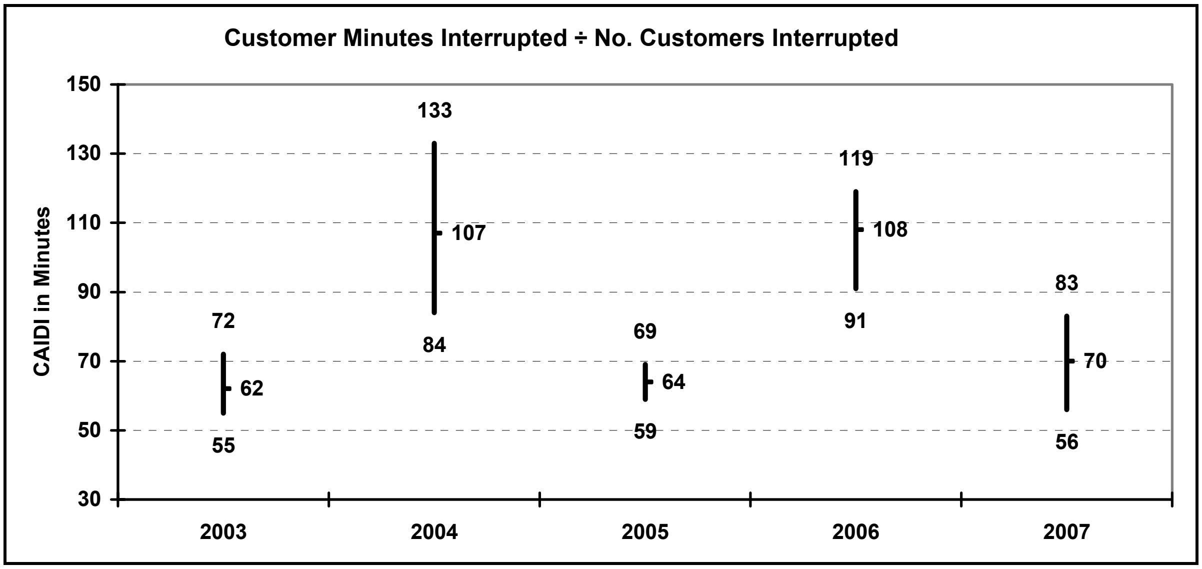


Figure 3-35 shows the maximum, average, and minimum adjusted CAIDI across FPUC's system. FPUC's average adjusted 2007 CAIDI index fell from 108 in 2006, to 70 in 2007 (35%).

Figure 3-35. CAIDI across FPUC's Two Regions (Adjusted)



The average length of time FPUC spends recovering from outage events, excluding hurricanes and other outage events, is the index L-Bar shown in Figure 3-36. FPUC's L-Bar decreased in this review period, from 84 minutes in 2006 to 77 minutes in 2007 (8%).

Figure 3-36. FPUC's Average Duration of Outages (Adjusted)

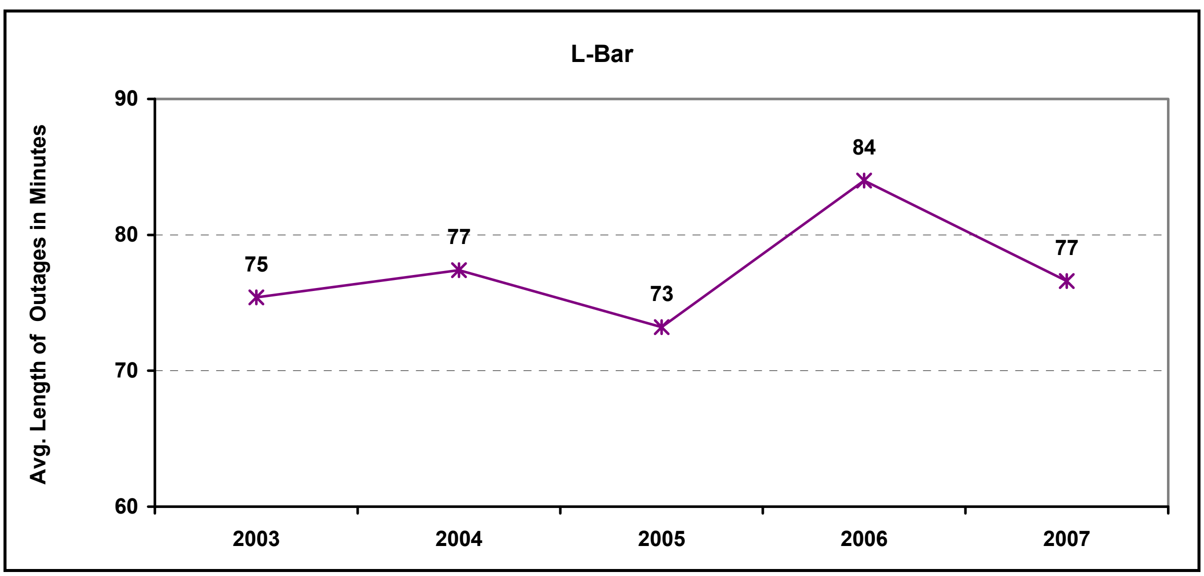
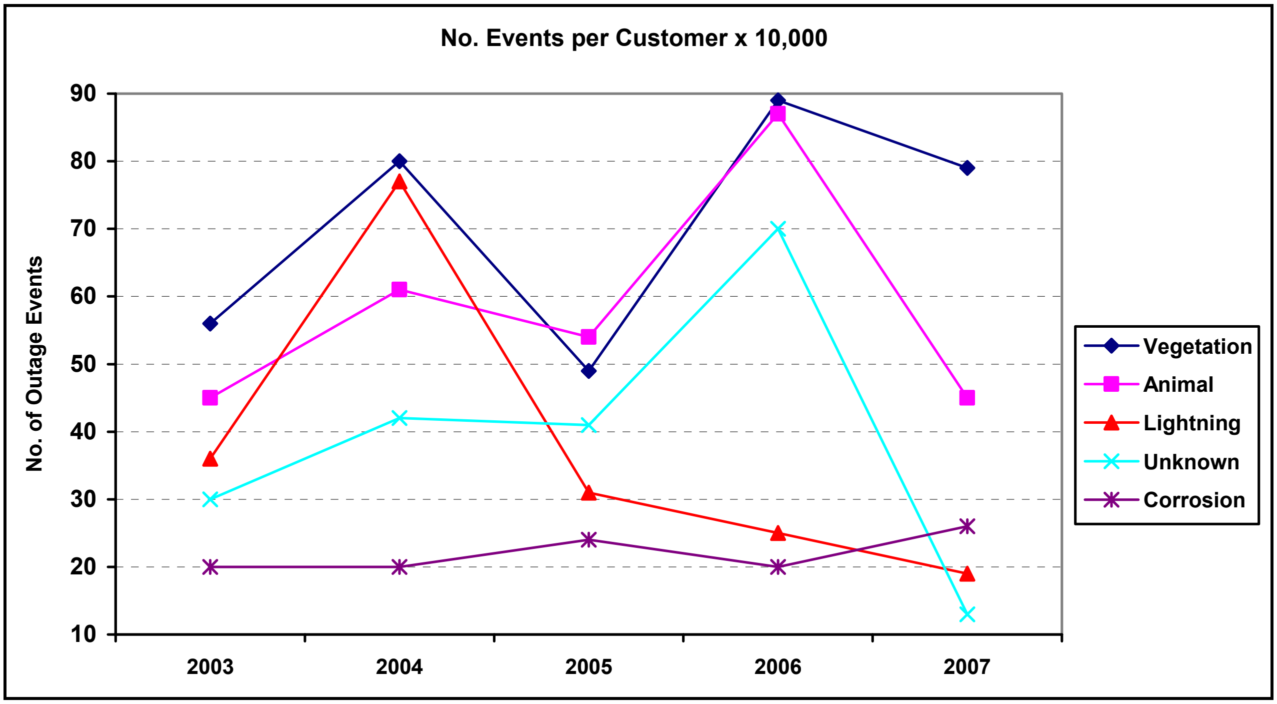


Figure 3-37 shows the top 5 causes of outage events on FPUC's distribution system per 10,000 customers. Large variations in the causes of outage events are not uncommon for a smaller utility.

Figure 3-37. FPUC's Top Five Outage Causes (Adjusted)



Rule 25-6.0455, F.A.C., waives the requirement to report information associated with the metrics MAIFIe and CEMI5 for any utility with fewer than 50,000 customers. FPUC qualifies for this waiver and did not file data pertaining to the metrics MAIFIe and CEMI5. FPUC's size probably affords its management immediate knowledge of where problems are and the nature of such problems. Additionally, the cost for the information systems necessary to measure MAIFIe and CEMI5 has a higher impact on small utilities compared to large utilities on a per customer basis. Nevertheless, FPUC is implementing system improvements one region at a time, improvements which will enable its management to review detailed performance data such as MAIFIe and CEMI5 for the entire FPUC system. FPUC now has the capability to report MAIFIe and CEMI5 for its Northwestern (Marianna) region.

Observations: FPUC's Adjusted Data

FPUC's 2007 overall service reliabilty data as measured by SAIDA, SAIFI, CAIDI and L-Bar has significantly improved from its 2006 levels.

Section IV. Inter-Utility Reliability Comparisons

Inter-Utility Reliability Trend Comparisons: Adjusted Data

Throughout the following discussion, it is important to remember that FPUC is a very small utility compared to the other IOUs. FPUC's size contributes to the volatility in its annual reliability data. Also, FPUC is exempt from reporting certain indices (MAIFIe and CEMI5) because FPUC has fewer than 50,000 customers. However, FPUC is gradually implementing information system upgrades that will enable data collection and reporting of the MAIFIe and CEMI5 reliability metrics.

Figure 4-1 is a ten-year graph of the adjusted SAIDI for each IOU. The increases in SAIDI for Gulf prior to 2000, and for TECO prior to 2003, are associated with upgrades to their information systems that began capturing more detailed outage data.

Figure 4-1. Average Interruption Duration (Adjusted SAIDI)

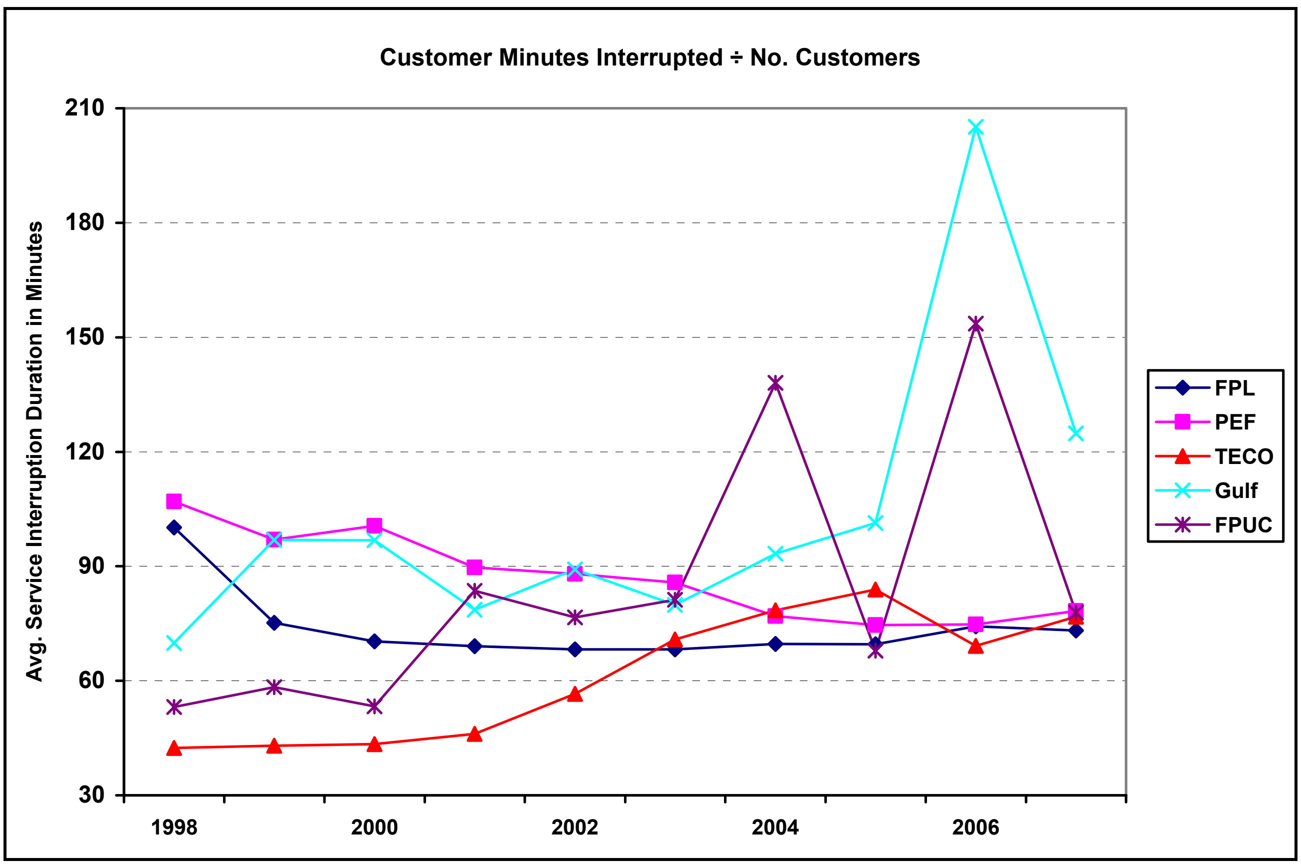


Figure 4-2 is a ten-year graph of the adjusted SAIFI of the Florida IOUs.

Figure 4-2. Average Number of Service Interruptions (Adjusted SAIFI)

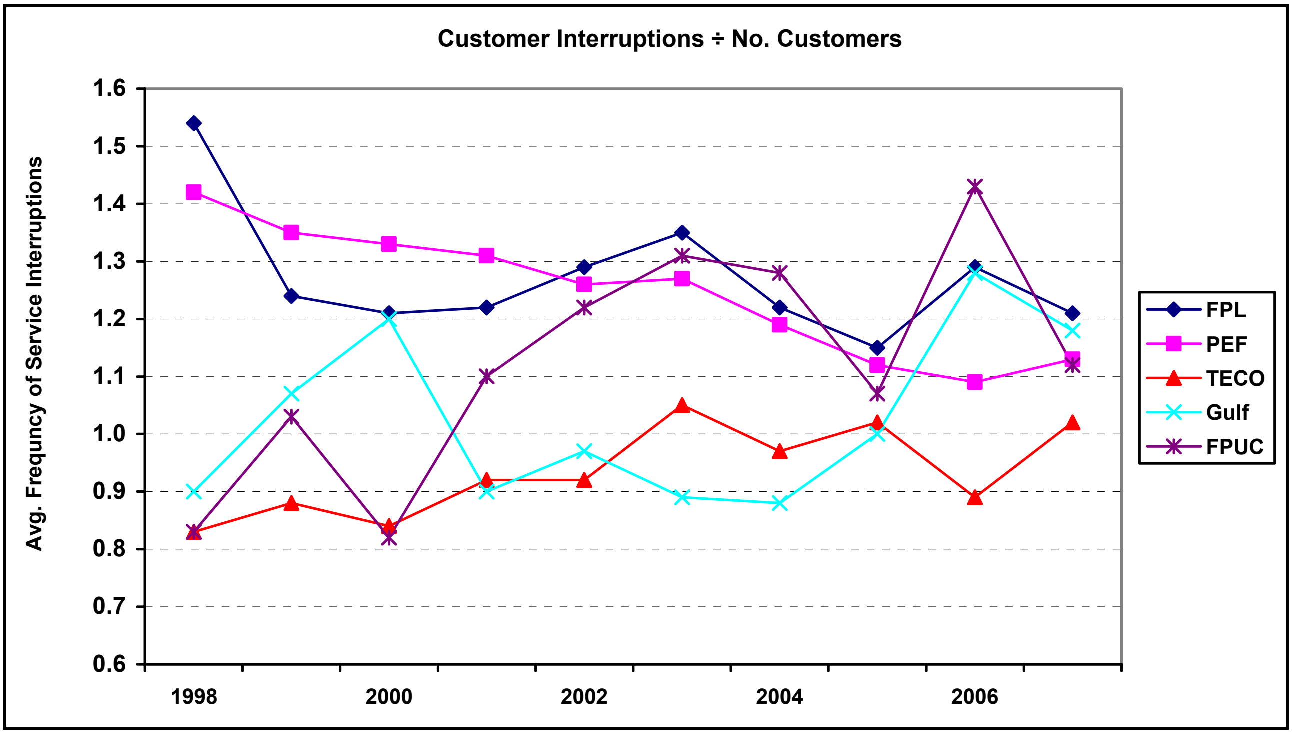


Figure 4-3 is a ten-year graph of the adjusted CAIDI of the Florida IOUs.

Figure 4-3. Average Service Restoration Time (Adjusted CAIDI)

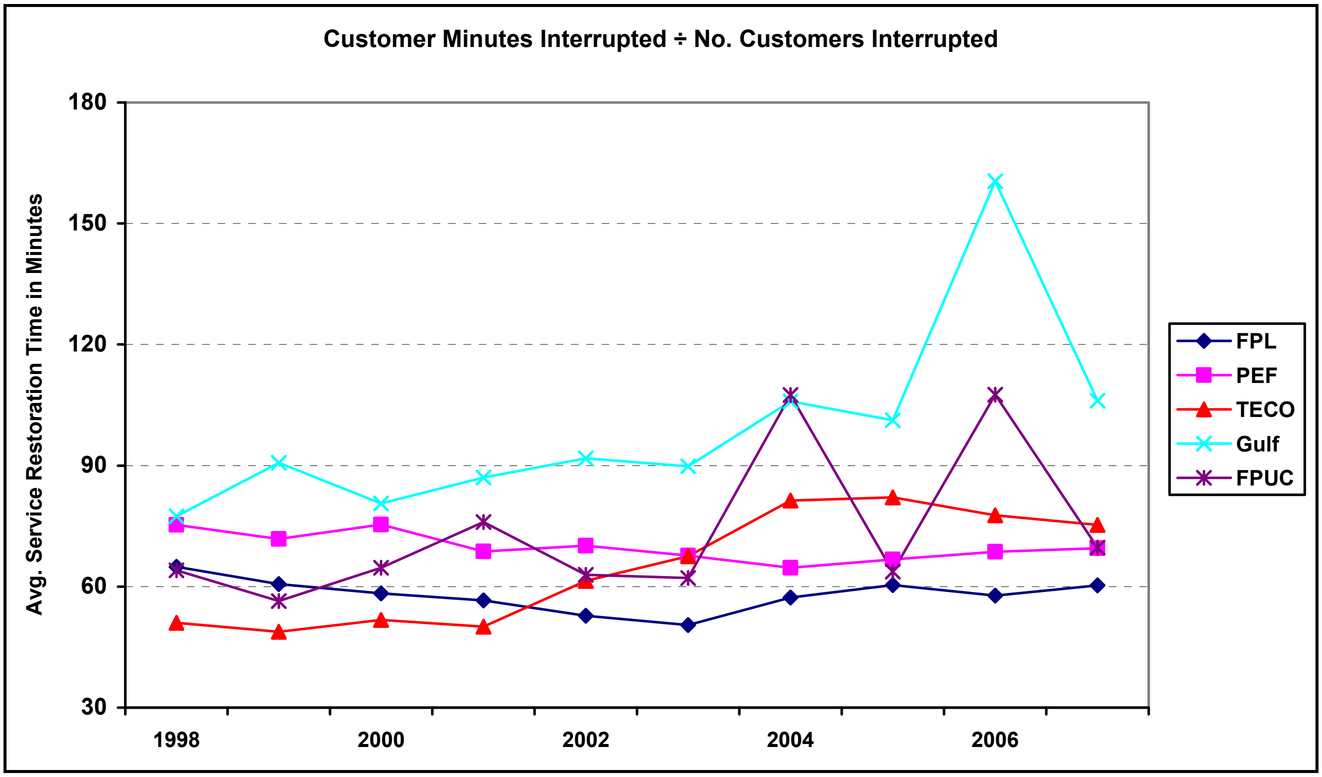


Figure 4-4 is a ten-year graph of the adjusted MAIFIe for FPL, PEF, TECO and Gulf.

Figure 4-4. Average Number of Feeder Momentary Events (Adjusted MAIFIe)

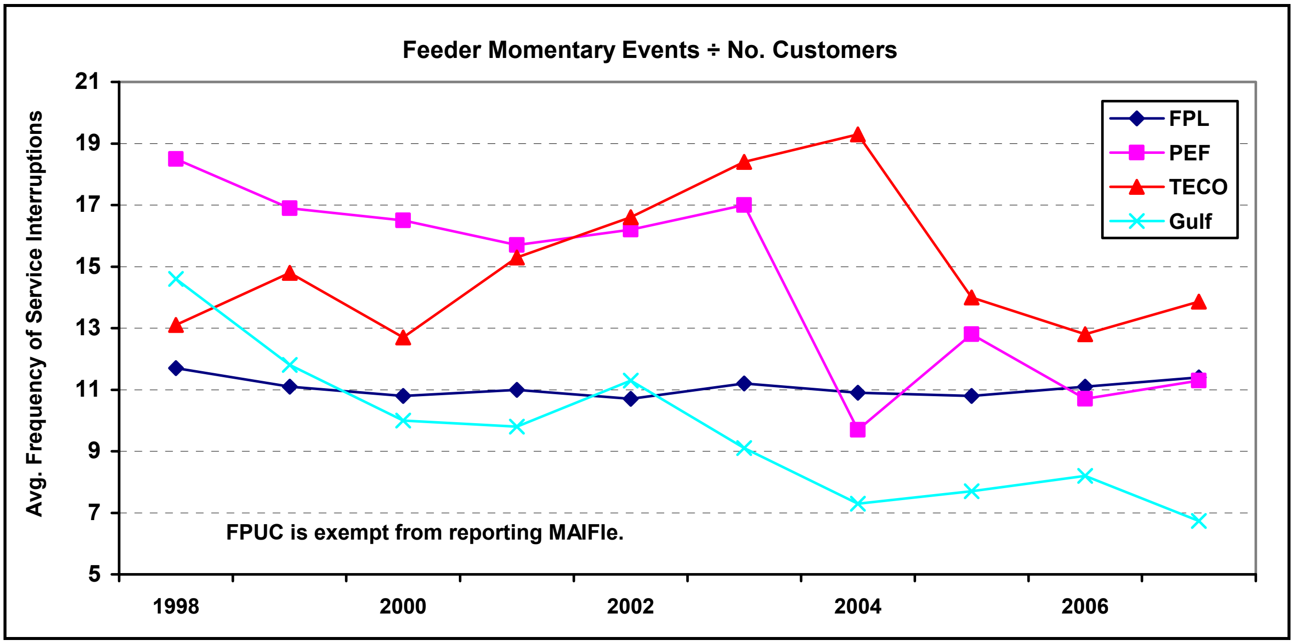
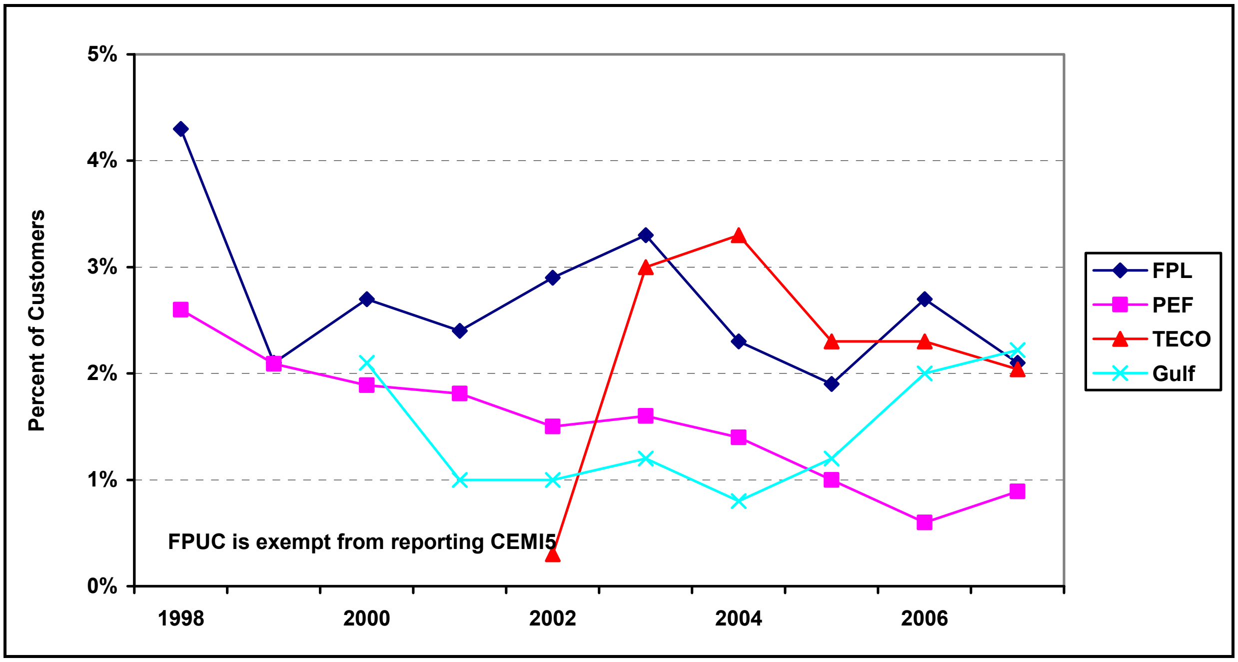


Figure 4-5 is a ten-year graph of the adjusted CEMI5 for FPL, PEF, TECO and Gulf. Prior to 2002, reporting was voluntary, which explains why data is not available for all IOUs during this ten-year period. IOUs with fewer than 50,000 customers are not required to report this metric; FPUC qualifies for this reporting waiver. TECO's increase in CEMI5 between 2002 and 2003 is attributable to the implementation of a new information system.

Figure 4-5. Percent of Customers with More Than Five Interruptions (Adjusted CEMI5)



The index N measures the primary causes of outage events and is also used to identify feeders with the most outage events. Figure 4-6 depicts the adjusted average number of outages events (N) per 10,000 customers for each of the Florida IOUs over a 10-year period.

Figure 4-6. Average Number of Outages per 10,000 Customers (Adjusted N)

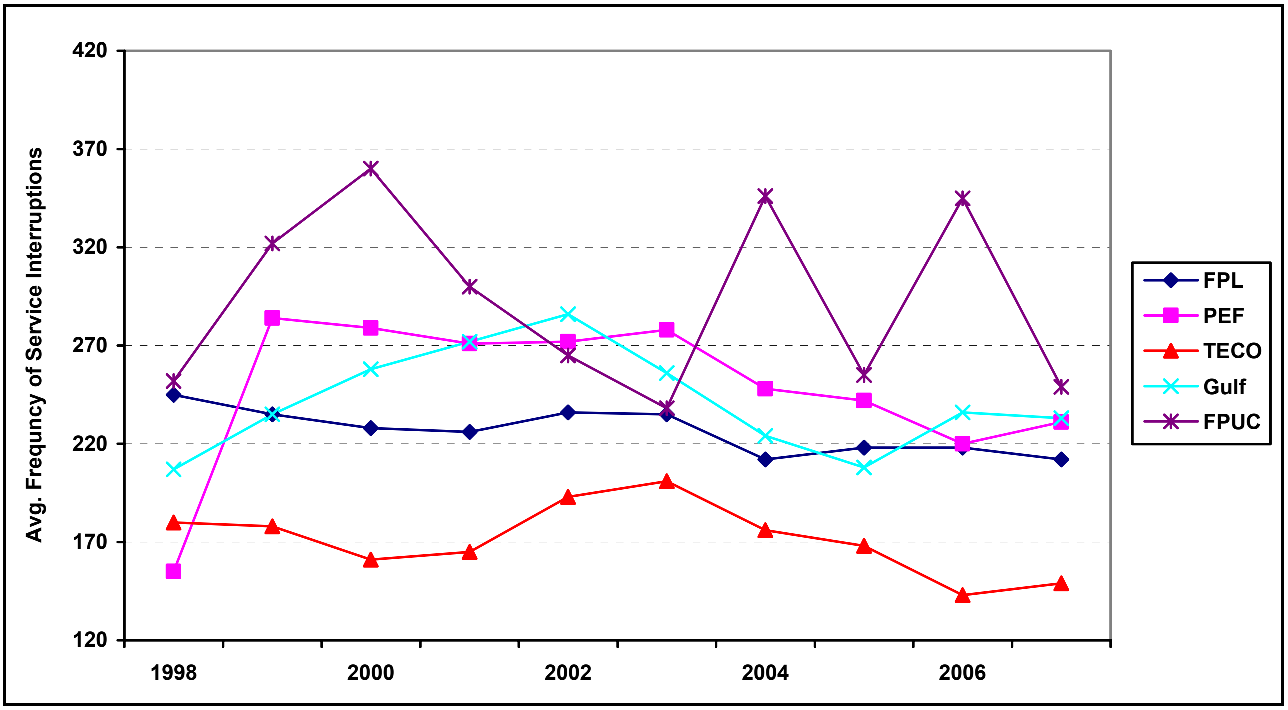
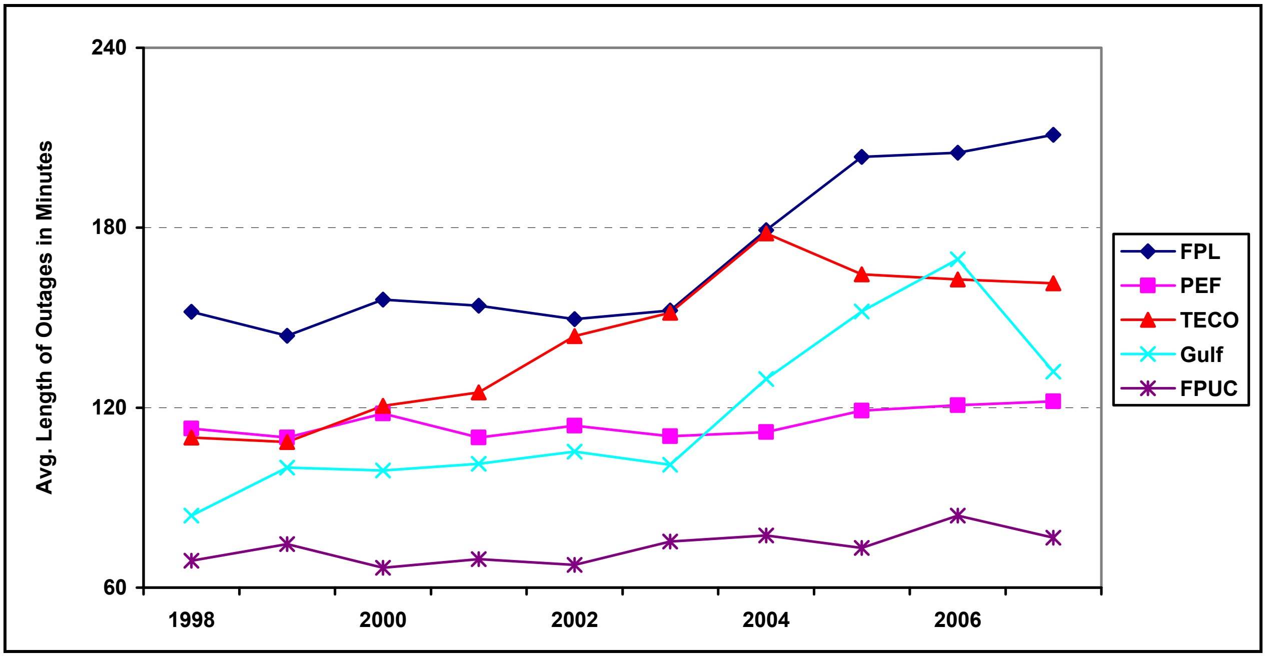


Figure 4-7 depicts the adjusted L-Bar for the Florida IOUs over a 10-year period.

Figure 4-7. Average Duration of Outage Events (Adjusted L-Bar)



Inter-Utility Comparisons of Reliability-Related Complaints

Each customer complaint received by the Commission is assigned a category after the complaint is resolved. Reliability-related complaints are those pertaining to trees, safety, repairs, quality of service, and service interruptions. Tracking complaints in concert with reliability performance began in 1999.

As shown in Figure 4-8, the percentage of reliability-related customer complaints for FPL, PEF, TECO, and Gulf has trended slightly downward from 2006 to 2007. The apparent volatility in FPUC's reliability-related customer complaints is due to FPUC's small customer base, which can exaggerate the significance of even a few complaints.

Figure 4-8. Percent of Complaints That Are Reliability-Related

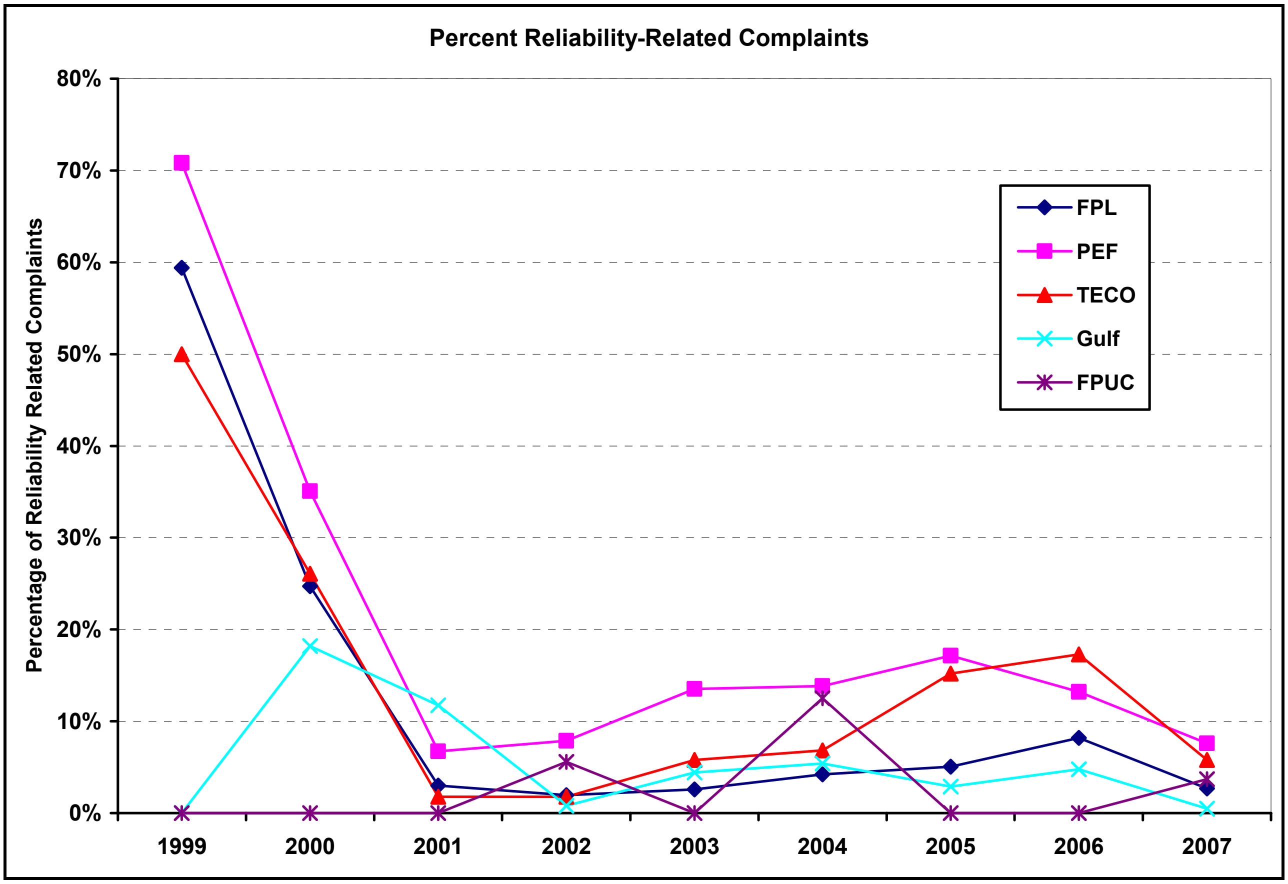
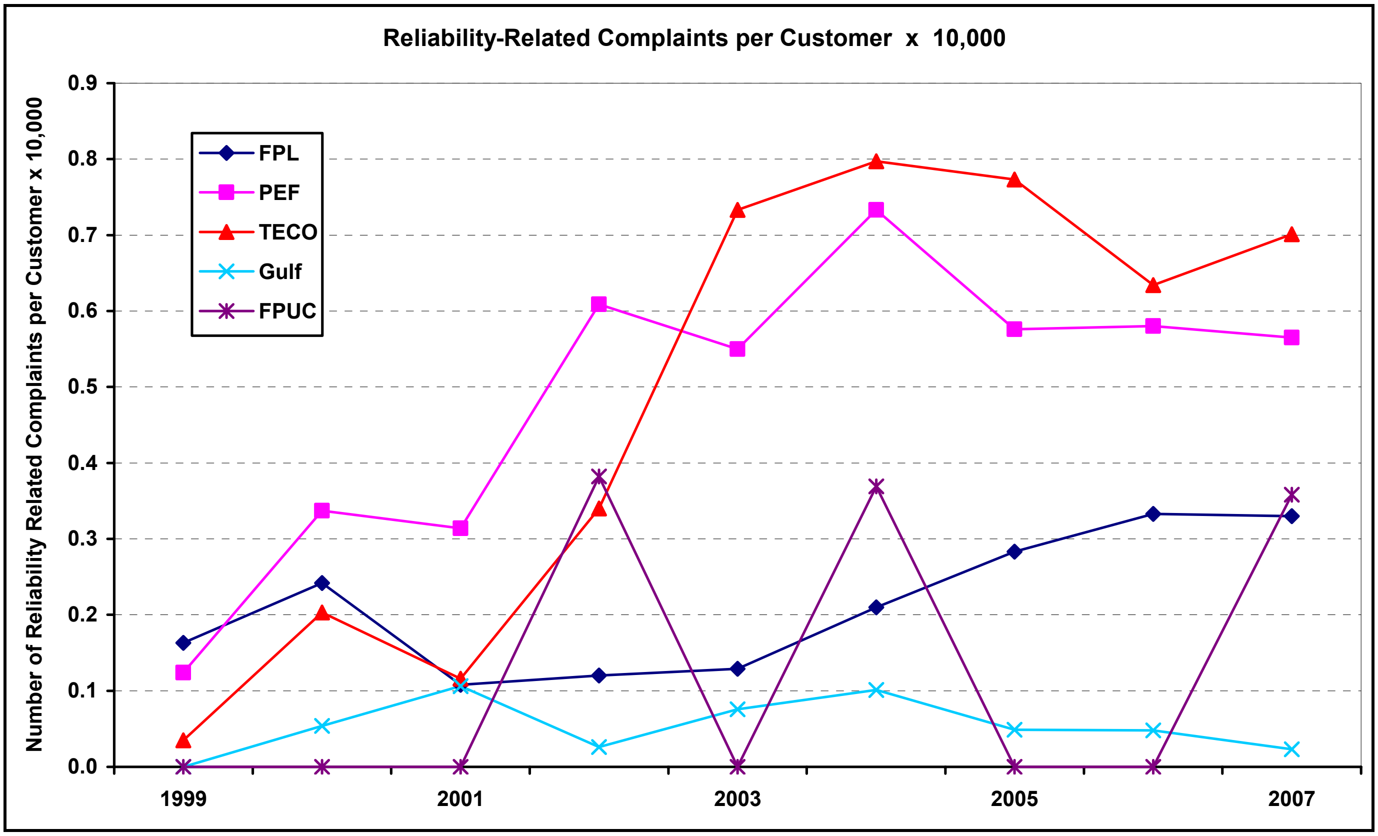


Figure 4-9 provides the number of reliability-related complaints per 10,000 customers for each utility. The data is normalized because utility size impacts both the volume of complaints and the significance of trends.

Figure 4-9. Service Reliability-Related Complaints



Conclusion

The Distribution Service Reliability Reports filed March 1, 2008 by FPL, PEF, TECO, Gulf, and FPUC pursuant to Rule 25-6.0455, Florida Administrative Code, contained the requisite data to review and assess reliability performance during 2007. Storm hardening activities are relatively new programs for each IOU. For this reason, the data collected for 2007 may not be representative of future levels for these activities. There were no observed trends in service reliability that warrant additional investigation such as a focused audit or other formal proceeding. Service reliability matters are monitored on an ongoing basis.

FPL

Some performance metrics improved in 2007 for FPL, while others declined. FPL's customers experienced fewer interruptions on a system-wide basis in 2007, but the average time to restore service to interrupted customers increased slightly. Reliability-related customer complaints for FPL trended downward in 2007.

PEF

In general, PEF's 2007 overall service reliability declined from 2006. PEF's customers experienced a greater number of momentary service interruptions lasting less than one minute in 2007 than in 2006. Also, customers experienced a higher number of system interruptions. On a positive note, reliability-related customer complaints continued to decrease in 2007.

TECO

TECO experienced increased outage duration over 2006 and a higher frequency of power interruptions, indicating decreasing reliability in these areas. On the other hand, the percent of customers experiencing more than five interruptions decreased in 2007 and the service restoration time from outage events improved, indicating improved reliability in these areas. Reliability-related customer complaints also decreased from 2006 to 2007.

Gulf

Gulf's overall service reliability improved significantly in 2007, even though the number of customers experiencing more than five interruptions actually increased. Gulf showed significant improvement in system outage frequency and durations from 2006. Reliability-related customer complaints decreased from 2006 to 2007.

FPUC

FPUC's overall service reliability improved significantly in 2007. The reliability indices suggest that the overall system experienced less frequent outages that were shorter in duration than in 2006. Even though reliability-related customer complaints increased for FPUC in 2007, this trend could be due to the company's small customer base which can exaggerate the significance of a few complaints.

Section V. Appendices

Appendix A. Adjusted Service Reliability Data

Florida Power & Light Company:

Table A-1. FPL's Number of Customers (Year End)

Region	2003	2004	2005	2006	2007
Gulf Coast	357,399	374,578	393,653	414,519	-
Ft. Myers	-	-	-	-	184,719
Naples	-	-	-	-	236,111
Manasota	336,408	342,322	351,134	358,098	360,152
Boca Raton	337,025	340,279	343,569	347,030	350,336
West Palm	314,635	322,670	332,194	337,612	340,513
Gulf Stream	304,203	310,684	313,158	316,390	318,594
Pompano	293,716	296,961	298,740	299,874	298,881
S. Dade	272,793	278,713	286,995	293,656	297,229
Brevard	259,357	264,851	272,758	281,090	284,097
Treasure Coast	229,436	237,794	252,063	264,835	270,525
C. Florida	230,764	241,517	253,134	261,990	265,365
Wingate	249,639	251,910	253,775	254,358	254,455
Central Dade	228,043	231,185	235,400	242,649	247,429
N. Dade	215,306	216,609	218,848	222,019	224,805
W. Dade	211,497	214,338	218,097	221,686	223,049
Toledo Blade	145,814	144,993	154,821	164,917	168,429
N. Florida	115,386	120,285	127,860	134,688	138,398
FPL System	4,101,421	4,189,689	4,306,199	4,415,411	4,463,087

Table A-2. FPL's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

Region	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
Gulf Coast	80	64	71	80	-	1.63	1.22	1.26	1.53	-	49.3	52.7	56.4	52.2	-
Ft. Myers	-	-	-	-	75	-	-	-	-	1.26	-	-	-	-	60.0
Naples	-	-	-	-	59	-	-	-	-	1.12	-	-	-	-	53.2
Manasota	59	61	54	66	68	1.06	0.84	0.83	1.01	0.87	55.0	72.4	65.2	66.0	77.8
Boca Raton	66	62	78	75	68	1.37	1.23	1.35	1.39	1.23	48.0	49.9	57.8	53.9	55.7
West Palm	63	66	76	84	71	1.19	1.16	1.27	1.27	1.21	52.9	56.7	59.9	65.7	58.4
Gulf Stream	54	50	56	60	55	1.29	1.06	1.04	1.28	1.13	42.0	47.0	53.6	46.6	48.7
Pompano	54	54	55	68	61	1.19	0.86	0.88	1.16	1.03	45.2	62.4	62.8	58.2	59.3
S. Dade	68	66	74	83	96	1.30	1.25	1.27	1.25	1.42	52.3	52.3	58.6	66.2	67.2
Brevard	66	84	63	55	70	1.32	1.32	1.02	1.03	1.16	50.1	61.2	61.9	53.9	60.0
Treasure Coast	100	117	101	81	95	1.90	1.77	1.43	1.41	1.31	52.8	65.9	70.7	57.5	72.0
C. Florida	100	107	74	70	84	1.89	1.73	1.31	1.27	1.2	52.6	61.9	56.9	54.9	56.4
Wingate	68	55	75	83	76	1.54	1.33	1.39	1.51	1.5	44.1	41.2	53.8	54.6	51.0
Central	47	49	55	64	64	0.94	0.91	1.02	1.05	1.49	49.7	54.2	53.9	60.8	53.4
N. Dade	63	74	76	78	72	1.10	1.13	1.03	1.19	1.13	57.5	65.2	73.6	65.2	63.8
W. Dade	56	64	72	94	78	1.20	1.10	1.30	1.64	1.4	46.3	58.4	55.7	57.4	55.6
Toledo Blade	61	93	6	82	74	1.00	1.44	0.82	1.42	0.96	61.5	64.7	74.5	57.6	77.1
N. Florida	117	96	80	74	94	1.90	1.61	1.10	1.14	1.38	61.9	59.9	72.2	65.2	68.5
FPL	68	70	70	74	73	1.35	1.22	1.15	1.29	1.21	50.5	57.3	60.4	57.8	60.3

Table A-3. FPL's Adjusted Regional Indices MAIFIe and CEMI5

Region	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than Five Service Interruptions (CEMI5)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
Gulf Coast	10.6	8.8	8.7	9.8	-	5.5%	1.6%	2.4%	3.1%	-
Ft. Myers	-	-	-	-	11.2	-	-	-	-	1.1%
Naples	-	-	-	-	8.3	-	-	-	-	4.3%
Manasota	8.3	8.1	8.5	9.3	9.2	1.4%	1.1%	1.0%	1.2%	1.1%
Boca Raton	8.1	9.7	8.2	8.8	9.3	2.8%	1.2%	1.1%	2.1%	2.3%
West Palm	14.1	11.3	11.4	11.7	11.2	2.4%	1.2%	2.5%	2.5%	1.9%
Gulf Stream	10.9	11.1	9.8	8.9	9.4	2.1%	1.8%	1.6%	5.4%	1.0%
Pompano	8.2	7.6	7.8	7.8	7.8	2.8%	0.4%	0.6%	2.3%	1.6%
S. Dade	12.9	11.5	11.9	10.3	10.1	3.2%	2.1%	3.1%	2.3%	3.3%
Brevard	15.3	13.9	14.1	15.8	16.8	1.7%	2.2%	0.5%	0.8%	0.9%
Treasure Coast	20.4	16.5	15.6	14.6	17.5	7.3%	6.3%	4.2%	4.6%	3.2%
C. Florida	10.9	13.3	15.1	12.8	14.0	6.9%	5.3%	2.8%	2.0%	1.8%
Wingate	8.3	11.2	12.0	12.8	12.3	3.1%	2.7%	2.2%	2.3%	3.0%
Central	7.8	9.0	7.8	8.9	10.0	0.8%	2.0%	2.1%	1.2%	1.8%
N. Dade	9.5	9.4	8.8	9.7	10.7	3.2%	3.1%	1.1%	2.5%	2.8%
W. Dade	14.4	11.2	9.8	10.6	9.8	2.0%	2.1%	2.0%	7.4%	2.9%
Toledo Blade	12.5	13.9	16.3	20.4	18.1	1.9%	4.6%	1.9%	2.9%	3.0%
N. Florida	8.3	12.8	13.2	12.5	12.9	7.7%	3.6%	1.9%	1.4%	2.4%
FPL System	11.2	10.9	10.8	11.1	11.4	3.3%	2.3%	1.9%	2.7%	2.1%

Table A-4. FPL's Primary Causes of Outage Events

Cause	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2003	2004	2005	2006	2007	Cumulative Percentages	2003	2004	2005	2006	2007
Equipment Failure	22,728	21,633	26,752	27,692	30,102	27.44%	200	217	249	255	256
Unknown	14,469	13,811	16,970	17,273	12,016	15.87%	128	149	149	183	170
Vegetation	19,307	15,225	10,571	8,911	12,201	14.09%	155	174	199	192	206
Animal	11,445	10,153	8,711	10,006	9,655	10.64%	74	79	113	113	115
All Other	4,296	6,261	5,842	5,318	7,343	6.19%	149	287	223	203	191
Other Weather	9,083	7,413	7,250	7,148	8,318	8.35%	106	132	144	156	164
Other	4,956	6,575	8,865	10,165	4,536	7.47%	155	178	184	193	208
Lightning	5,074	4,212	4,682	4,575	6,059	5.24%	233	262	289	301	306
Equipment Connect	2,339	1,932	2,288	2,925	2,631	2.58%	163	171	217	227	228
Vehicle	1,791	1,751	1,905	2,181	1,678	1.98%	194	204	236	231	228
Dig-in	767	-	-	-	-	0.16%	207	-	-	-	-
FPL System	96,255	88,966	93,836	96,194	94,539	100.0%	150	179	204	205	211

Notes:
(1) "All Other" category is the sum of many diverse causes of outage events which individually are not among the top ten causes of outage events and excludes those identified as "Other."
(2) "Other" category is a sum of outage events that require a detailed explanation.
(3) Blanks are shown for years where the number of outages was too small to be among the top ten causes of outage events
(4) Beginning in 2007, FPL's Gulf Coast region was divided into two separate regions, Ft. Myers and Naples.

Progress Energy Florida, Inc.:

Table A-5. PEF's Number of Customers (Year End)

Region	2003	2004	2005	2006	2007
S. Coastal	530,387	638,170	647,997	651,800	651,029
S. Central	344,656	360,327	384,292	401,943	411,225
N. Central	421,595	366,161	363,656	371,357	373,325
N. Coastal	211,999	176,744	183,861	190,414	192,295
PEF System	1,508,637	1,541,402	1,579,806	1,615,514	1,627,874

Note: PEF changed the boundaries of its regions in 2002-2003.

Table A-6. PEF's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

Region	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
S. Coastal	66	66	64	70	61	1.13	1.09	1.04	1.07	1.05	58.8	60.7	61.8	65.2	58.7
S. Central	78	68	82	75	71	1.05	1.10	1.24	1.12	1.02	74.1	62.0	66.7	66.5	69.9
N. Central	107	77	73	77	81	1.56	1.22	1.09	1.13	1.13	68.8	63.2	67.2	68.1	71.9
N. Coastal	104	132	98	89	144	1.38	1.64	1.21	1.02	1.61	75.8	80.3	80.7	86.9	89.7
PEF	86	77	75	75	78	1.27	1.19	1.12	1.09	1.13	67.7	64.7	66.7	68.6	69.5

Table A-7. PEF's Adjusted Regional Indices MAIFIe and CEMI5

Region	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than Five Service Interruptions (CEMI5)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
S. Coastal	18.0	14.7	12.8	12.5	12.9	0.68%	1.14%	0.62%	0.51%	0.55%
S. Central	17.4	12.8	13.9	10.6	10.1	0.90%	0.47%	1.68%	0.44%	0.36%
N. Central	15.4	11.3	12.3	9.1	9.9	2.56%	1.00%	0.78%	0.77%	1.08%
N. Coastal	17.4	11.5	11.2	8.2	11.5	2.96%	4.76%	1.48%	0.60%	2.75%
PEF System	17.0	13.1	12.8	10.8	11.3	1.58%	1.37%	1.01%	0.56%	0.89%

Table A-8. PEF's Primary Causes of Outage Events

Cause	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2003	2004	2005	2006	2007	Cumulative Percentages	2003	2004	2005	2006	2007
Animals	5,044	5,422	4,430	4,602	4,414	12.48%	60	58	65	67	65
Storm	6,472	4,208	3,337	4,534	3,817	11.68%	104	106	111	100.4	105
Tree-preventable	5,380	4,546	3,814	3,552	3,728	10.97%	112	113	107	109	113
Unknown	4,964	4,362	4,058	3,685	3,973	10.99%	73	73	74	74	74
All Other	3,748	3,285	3,946	3,064	3,101	8.95%	107	107	115	138	119
Defective Equip.	3,382	3,289	3,694	3,317	3,144	8.78%	169	165	180	181	186
Underground Sec. / Service	3,522	3,450	4,139	4,464	4,122	10.28%	139	156	156	158	166
Connector Failure	2,923	2,830	2,853	2,967	3,010	7.61%	92	95	102	106	102
Tree Non-preventable	2,757	2,247	2,044	1,823	3,197	6.30%	125	116	112	119	133
Underground Primary	2,578	2,323	2,586	2,735	2,566	6.68%	173	176	198	184	188
Lightning	1,103	2,287	3,277	875	2,551	5.27%	157	125	116	189	131
PEF System	41,873	38,249	38,178	35,618	37,623	100%	111	112	119	121	122

Notes:

(1) "All Other" category is the sum of diverse causes of outage events which individually are not among the top ten causes of outage events.

Tampa Electric Company:

Table A-9. TECO's Number of Customers (Year End)

Region	2003	2004	2005	2006	2007
Western	181,164	182,791	184,826	185,868	187,390
Central	168,119	171,187	175,919	179,020	180,380
Eastern	95,517	98,326	102,328	105,687	107,861
Winter Haven	62,015	63,013	64,981	67,362	67,775
S. Hillsborough	45,837	49,271	53,627	57,675	59,315
Plant City	48,885	50,032	51,633	53,081	53,612
Dade City	12,644	13,000	13,421	13,818	13,778
TECO System	614,181	627,620	646,735	662,511	670,111

Table A-10. TECO's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

Region	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
Western	66	59	75	64	77	0.86	0.69	0.88	0.75	.95	76	85	85	85	81
Central	60	82	61	55	62	0.80	0.84	0.77	0.67	.84	74	98	79	83	75
Eastern	62	81	97	62	77	1.14	1.02	1.13	0.87	1.11	54	80	86	71	70
Winter Haven	65	71	65	58	66	1.16	1.04	1.01	1.00	.91	56	68	65	58	72
S. Hillsborough	90	89	127	96	74	1.21	1.33	1.38	1.15	1.12	75	67	92	84	66
Plant City	120	105	130	96	128	1.83	1.58	1.69	1.25	1.54	66	67	77	77	83
Dade City	130	174	148	209	127	2.19	1.95	1.50	2.78	1.74	59	90	98	75	73
TECO	71	78	84	69	77	1.05	0.97	1.02	0.89	1.02	68	81	82	78	75

Table A-11. TECO's Adjusted Regional Indices MAIFIe and CEMI5

Region	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than Five Service Interruptions (CEMI5)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
Western	17.9	15.2	11.4	12.6	12.1	0.52%	0.44%	0.57%	0.61%	1.97%
Central	14.7	16.3	11.2	10.6	11.7	3.81%	1.17%	0.52%	0.35%	1.22%
Eastern	17.8	20.7	15.5	12.6	15.8	0.99%	3.57%	1.20%	0.66%	2.98%
Winter Haven	17.8	23.4	15.8	12.3	13.6	1.55%	5.16%	0.49%	1.19%	0.31%
S. Hillsborough	25.7	26.6	19.4	15.4	14.7	7.28%	3.69%	8.52%	1.05%	2.45%
Plant City	24.5	26.3	19.6	17.3	19.9	8.35%	14.45%	13.31%	11.05%	3.82%
Dade City	30.6	33.4	22.6	21.8	25.4	14.78%	15.85%	0.63%	37.90%	6.13%
TECO System	18.4	19.3	14.0	12.8	13.9	3.02%	3.30%	2.33%	2.26%	2.04%

Table A-12. TECO's Primary Causes of Outage Events

Cause	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2003	2004	2005	2006	2007	Cumulative Percentages	2003	2004	2005	2006	2007
Lightning	2,481	2,283	1,962	1,723	1,921	19.30%	241	246	220	224	222
Animal	2,192	2,083	1,742	1,656	1,708	17.46%	79	93	91	82	81
Vegetation	2,003	1,880	1,797	1,564	2,086	17.36%	172	202	157	153	157
Unknown	1,487	1,335	1,243	895	727	10.58%	191	146	130	123	113
Other Weather	1,009	911	930	703	578	7.69%	160	187	161	163	151
Electrical	1,122	955	1,065	954	979	9.45%	154	180	190	189	179
Bad Connection	841	694	917	704	726	7.23%	158	179	182	186	188
Human Interference	-	222	266	-	-	0.91%	-	193	200	-	-
Vehicle	348	235	349	334	261	2.84%	163	169	182	180	184
Defective Equipment	317	210	291	441	508	3.29%	182	207	217	209	219
All Other	276	235	311	264	254	2.49%	138	187	174	177	152
Down Wire	265	-	-	237	249	1.40%	177	-	-	197	170
TECO System	12,341	11,043	10,873	9,475	9,997	100.0%	167	178	164	163	162

Notes:
(1) "All Other" category is the sum of many diverse causes of outage events which individually are not among the top ten causes of outage events.
(2) Blanks are shown for years where the number of outages was too small to be among the top ten causes of outage events.

Gulf Power Company:

Table A-13. Gulf's Number of Customers (Year End)

Region	2003	2004	2005	2006	2007
Western	197,690	194,705	184,826	205,779	208,436
Central	100,660	97,849	175,919	108,859	109,817
Eastern	95,508	103,220	102,328	104,254	109,410
Gulf System	393,858	395,774	463,073	418,892	427,663

Table A-14. Gulf's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

Region	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
Western	86	115	142	158	146	0.94	1.07	1.35	1.27	1.32	91	108	105	124	110
Central	73	69	73	174	109	0.84	0.65	0.81	1.28	0.95	87	105	90	136	115
Eastern	75	75	78	331	100	0.84	0.75	0.71	1.29	1.12	90	101	111	257	90
Gulf	80	93	101	205	125	0.89	0.88	1.00	1.28	1.18	90	106	101	161	106

Table A-15. Gulf's Adjusted Regional Indices MAIFIe and CEMI5

Region	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
Western	10.9	8.9	11.6	9.3	7.4	1.65%	1.24%	1.17%	2.01%	2.15%
Central	8.5	5.3	4.7	7.5	7.6	0.26%	0.39%	1.56%	2.01%	0.52%
Eastern	6.0	6.4	5.8	6.7	4.8	1.13%	0.39%	0.64%	2.06%	4.08%
Gulf System	9.1	7.3	7.7	8.2	6.7	1.17%	0.81%	1.20%	2.02%	2.22%

Table A-16. Gulf's Primary Causes of Outage Events

Cause	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2003	2004	2005	2006	2007	Cumulative Percentages	2003	2004	2005	2006	2007
Animal	3,000	2,012	1,486	1,609	2,089	21.00%	67	81	92	163	83
Lightning	1,885	1,541	1,851	2,307	2,112	19.97%	123	151	192	170	151
Deterioration	1,594	1,611	1,634	1,914	2,188	18.42%	134	162	188	174	165
Unknown	1,616	1,390	980	987	742	11.77%	96	136	141	157	91
Trees	1,016	1,193	254	1,292	1,419	10.66%	106	129	139	157	144
Vehicle	227	303	2,239	284	336	6.98%	147	162	171	381	165
All Other	217	264	288	299	345	2.91%	132	126	110	139	96
Wind / Rain	100	118	235	680	175	2.69%	145	125	146	219	160
Overload	201	212	129	223	271	2.13%	93	125	108	156	99
Vines	128	117	424	-	-	1.38%	87	98	-	-	-
Other	85	121	129	-	-	0.69%	100	124	217	-	-
Contamination / Corrosion	-	-	118	137	143	0.82%	-	-	194	182	127
Dig-In	-	-	-	144	130	0.56%	-	-	-	109	210
Gulf System	10,069	8,882	9,767	9,876	9,950	100%	101	130	152	114	132

Notes:
(1) "All Other" category is the sum of many diverse causes of outage events which individually are not among the top ten causes of outage events.
(2) Blanks are shown for years where the number of outages was too small to be among the top ten causes of outage events.

Florida Public Utilities Company:

Table A-17. FPUC's Number of Customers (Year End)

Region	2003	2004	2005	2006	2007
Fernandina(NE)	14,448	14,566	14,731	14,859	15,120
Marianna (NW)	12,598	12,528	12,661	13,934	12,846
FPUC System	27,046	27,094	27,392	28,793	27,966

Table A-18. FPUC's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

Region	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
NE	77	152	59	105	87	1.07	1.15	1.01	1.15	1.05	72	133	59	91	83
NW	86	122	78	206	67	1.58	1.44	1.13	1.72	1.19	55	84	69	119	56
FPUC	81	138	68	154	78	1.31	1.28	1.07	1.43	1.12	62	107	64	108	70

Table A-19. FPUC's Primary Causes of Outage Events

Cause	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2003	2004	2005	2006	2007	Cumulative Percentages	2003	2004	2005	2006	2007
Vegetation	153	216	135	257	220	24.72%	72	80	83	95	73
Animal	124	164	149	250	127	20.51%	44	48	49	50	57
Lightning	100	208	84	72	52	13.00%	65	81	72	99	60
Unknown	82	113	113	202	37	13.78%	50	55	49	69	74
Corrosion	56	53	66	59	74	7.76%	157	115	116	124	100
All Other	30	45	40	33	43	4.81%	87	86	75	73	56
Other Weather	31	49	20	50	67	5.47%	82	124	69	103	75
Trans. Failure	37	27	38	32	35	4.26%	142	161	154	170	83
Vehicle	11	16	14	28	27	2.42%	73	91	68	162	107
Cut-Out Failure	13	26	12	5	4	1.51%	70	71	74	55	61
Fuse Failure		21	27	6	6	1.51%	-	49	47	95	53
Dig-in	6	-	-	-	4	0.25%	92	-	-	-	98
FPUC System	643	938	698	994	696	100%	75	77	73	84	77

Notes:

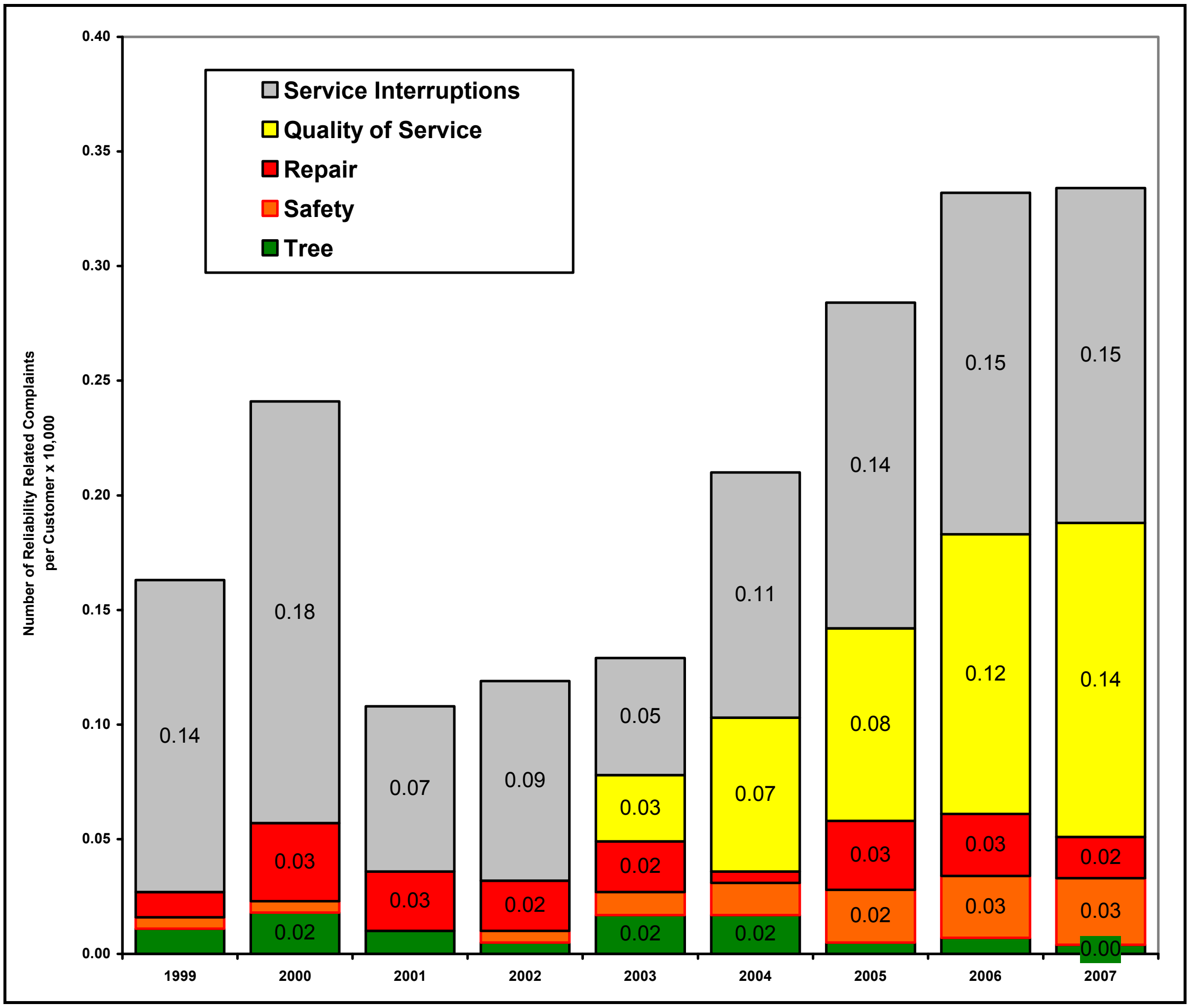
(1) "All Other" category is the sum of many diverse causes of outage events which individually are not one of the top ten causes of outage events.

(2) Blanks are shown for years where the quantity of outages was less than one of the top ten causes of outage events.

Appendix B. Service Reliability Customer Complaints

Each customer complaint received by the Commission is assigned a category after the complaint is resolved. Reliability-related complaints are those pertaining to trees, safety, repairs, quality of service, or service interruptions.[24] The "quality of service" category was established in July 2003, resulting in a shift of some complaints that previously would have been coded in another complaint category. The volume of service reliability-related complaints is multiplied to 10,000 customers for comparative purposes.

Figure B-1. FPL's Service Reliability Complaints



[24] A quality of service customer complaint typically includes one or more aspects of service reliability (i.e., momentary events, service interruptions, trees, safety, or repairs) and possibly other matters such as a high bill.

Figure B-2. PEF's Service Reliability Complaints

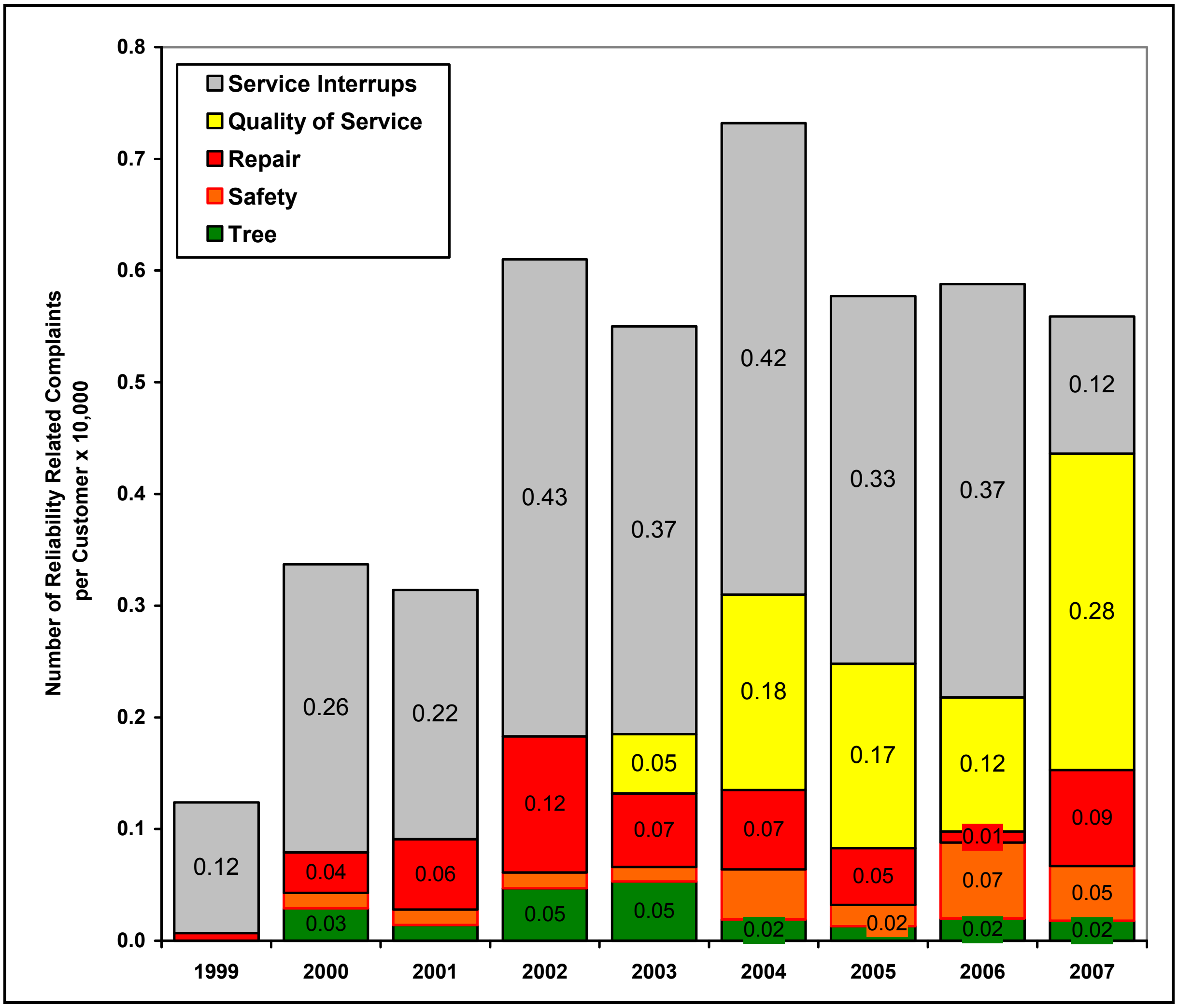


Figure B-3. TECO's Service Reliability Complaints

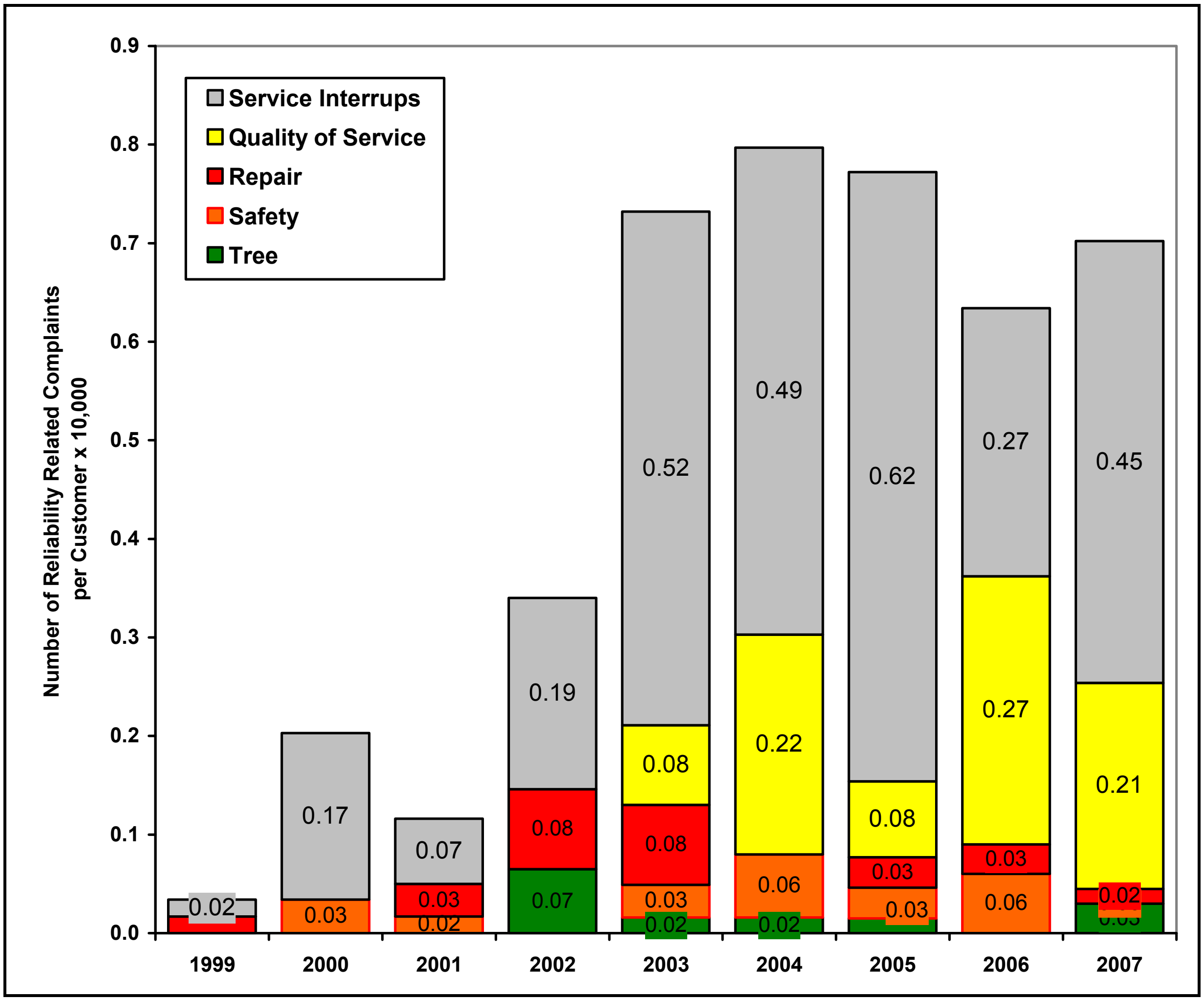


Figure B-4. Gulf's Service Reliability Complaints

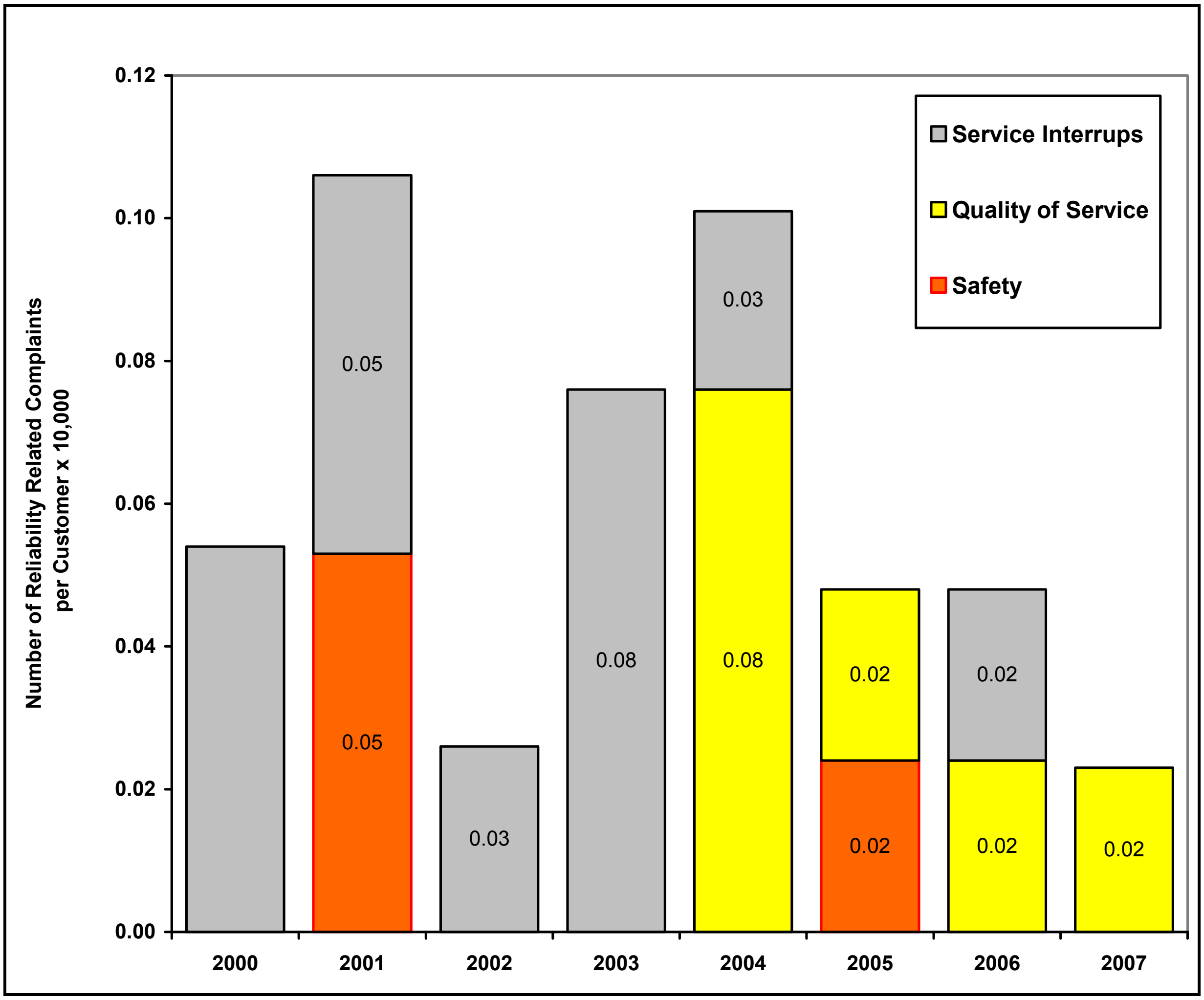
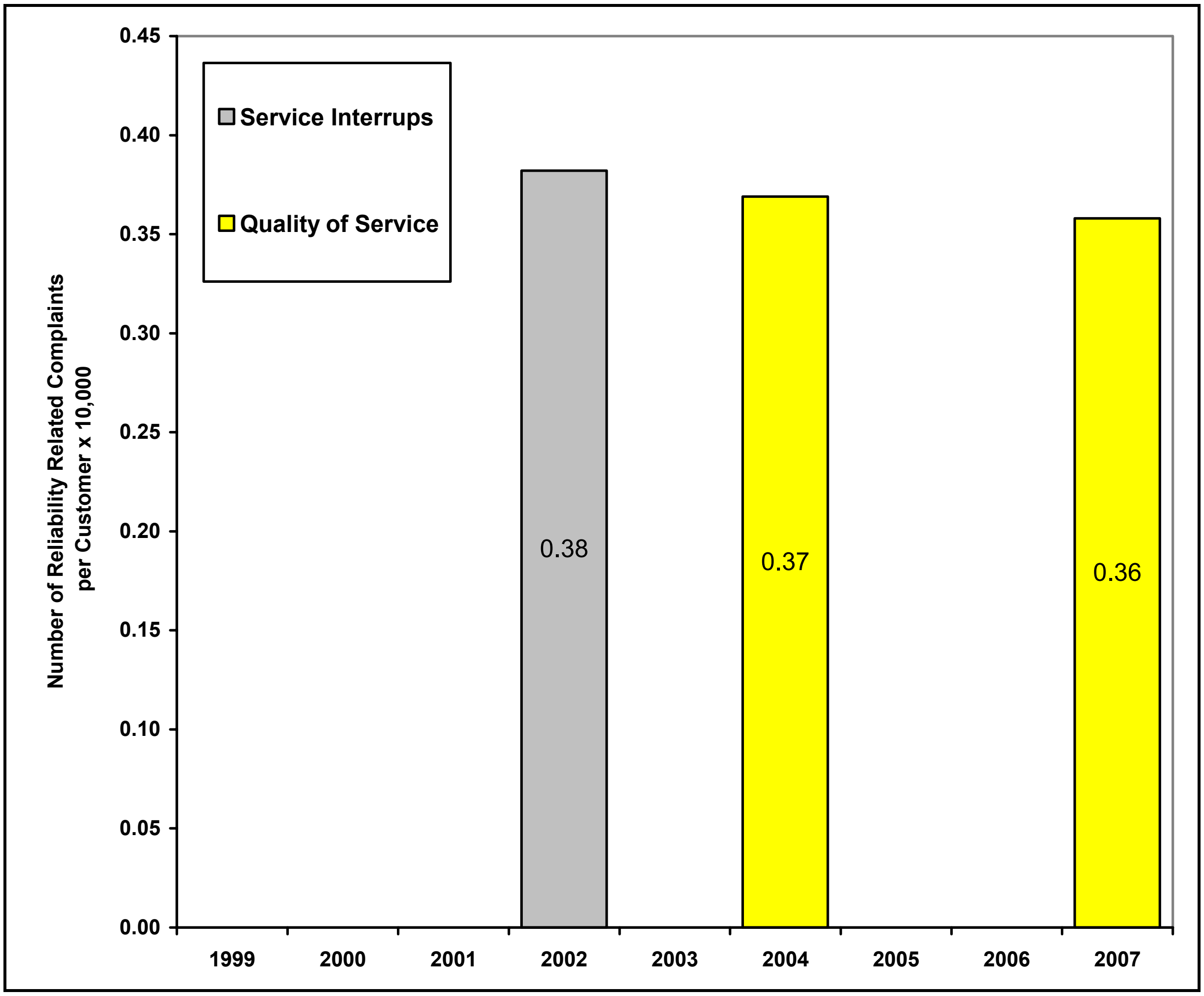


Figure B-5. FPUC's Service Reliability Complaints



Appendix C. Summary of 2007 Rural Electric Cooperative Utility Reports

Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2007												
	The extent to which Standards of Construction address:						**Transmission & Distribution Facility Inspections:**				**Vegetation Management**	
Utility	**Comply with the 2007 NESC on or after 2/1/2007**	**Guided by Extreme Wind Loading per Figure 250-2(d)**		**Effects of flooding & storm surges on UG & OH distribution facilities**	**Placement of distribution facilities to facilitate safe and efficient access**	**Written safety, pole reliability, pole loading capacity, and engineering standards for Attachments**	**Description of policies, guidelines, practices, procedures, cycles, and pole selection.**	**Number and percent of poles and structures planned & completed**	**Number and percent of poles and structures failing inspection with reasons**	**Number and percent of poles and structures, by class, replaced or remediated with description**	**Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation.**	**Quantify, level, and scope planned and completed for transmission and distribution.**
		Major Planned Work, Expansion, Rebuild, or Relocation	**Targeted Critical Infrastructure and major thoroughfares**									
Central Florida Electric Cooperative, Inc.	Yes	Not on a system wide basis. Using 100-130 mph wind loads in certain cases. Waiting for PURC granular wind research results.		Under review	Yes. Does not install in rear of property.	Yes	T: 1-yr D: 8-yr Program	T: Planned and inspected all 12 miles of transmission (100%) D: 11,800 (14.3%)	T: not specified D: 47 out of 11,800 were deteriorated	No details	Currently 3 years into right of way plan. Trees are trimmed or removed 10 feet of all main lines.	5-yr right of way vegetation clearance plan.
Choctawhatchee Electric Cooperative, Inc.	Yes	Guided by 2002 Figure 250-2(d)		Yes	Yes	Yes	D: 8-yr cycle (5,000 -7,000 poles annually)	D: 6,162 (10.4%)	D: 42 (0.007%)	D: Replaced 42	D: 5-Yr cycle	20% of system
Clay Electric Cooperative, Inc.	Yes	Guided by 2002 Figure 250-2(d)		Not applicable. Non-coastal utility.	Yes	Yes. Plans to inspect attachments in 2008.	T: Visual (2-yr), climbing (4-yr) D: 10-yr cycle back in 2006	T: 2,781 (100%) D: 25,653 planned (~13.5%) D: 28,926 (15.2%) completed	T: 36 decay (1.29%) D: 217 rejected (0.75%)	T: 21 replaced D: replaced (217)	T: 3-Yr cycle D: avg 4-yr cycle (City 3-yr, Urban 4-yr, Rural 5-yr)	133% of plan
Escambia River Electric Cooperative	Yes	Guided by 2002 Figure 250-2(d) on or after 12/10/2006.		Not applicable. Non-coastal utility.	Yes	Yes	No transmission poles D: 8-yr cycle	Planned 3,740 (12.5%) Completed 4,063 (13%)	5 Decay (0.12%)	Replaced 5	5-yr cycle for all distribution lines.	102% of plan

Florida Keys Electric Cooperative Association, Inc.	Yes	Guided by EWL on or after 4/24/2007.	Under review.	Yes	Yes	T: Visual (1-Yr) D: 5-yr cycle	T: Number not reported (100%) D: Planned 20% D: 3020 (20%) completed	T: 0 D: 266 (8.8%)	T: 0 D: 170 replaced. Remaining 96 are currently being replaced.	T: 1-yr cycle D: 3-yr cycle	100% of plan
Glades Electric Cooperative, Inc.	Yes	Guided by 2002 Figure 250-2(d)	Under review	Yes	Yes	10-yr cycle for all wooden poles.	T: 100% of 87 miles of system by aerial inspections. Climbing inspections completed on 90 structures (10.6% of system.) D: 3,756 (9.4% of System.)	T: 3 (3.3%) ground line decay D: 194 (5.2%) D: Decay 160 (4.3%) D: Other 34 (0.9%)	T: 3 replaced D: 92 repaired (banded truss reinforcement) D: 102 replaced.	3-yr trimming cycle all circuits.	100% of plan
Gulf Coast Electric Cooperative, Inc.	Yes	NESC Grade C. (Not EWL.) However, GCEC does meet the "design to withstand, without conductors, extreme wind loading in Rule 250C applied in any direction to the structure."	Under review and waiting for the results of PURC research.	Yes	Yes	Distribution Only Company. D: RUS Bulletin 1730B-121 (avg 8-yr Cycle)	D: 10,275 poles inspected (22.5%)	241 (2.3%). No main reason stated.	Not reported.	5-yr cycle	100% of plan
Lee County Electric Cooperative Inc.	Yes	Guided by 2002 Figure 250-2(d)	Yes	Yes. Uses mostly front lots.	Yes. Does not permit attachment to transmission poles.	T: Annual (230 kV) 2-yr cycle (138 kV) D: 10-yr	T: 1520 (57.5%) + 100% of 230 kV facilities + 47% of the 138 kV facilities D: 24,796 (23.6% of total number of poles.	T: 224 (14.7%) failed, 56 rotted, 168 woodpecker D: 1688 (6.8% of inspection, 1.6% of total) 101 rot, 1413 plumb, 174 woodpecker	T: 74 (33%) will be replaced between '07-'08; patched 150 (67%) D: 101 (6%) replumb; 1413 (83.7%) replaced; 174 (10.3%) patched	T: 230KV bi-annual; 138KV annual D: 3-yr (2&3-Phase circuits); 6-yr (1-Phase circuits)	100% of plan for transmission. 141% of scheduled for distribution system.
Okefenokee Rural Electric Membership Corporation	Yes	No. Not at this time.	Under review	Yes	Yes. With the exception of BellSouth of Florida and BellSouth of Georgia.	Distribution Only company. D: RUS Bulletin 1730B-121 8-yr inspection cycle	D: 7,463 poles inspected (13.5% of the 55,414 poles on system as of December 2007	D: 33 (0.44% of inspected poles) decay	D: 10 replaced D: 23 scheduled for remediation in Spring 2008	D: 5-yr trim cycle all circuits.	100% of plan

Peace River Electric Cooperative, Inc.	Yes	No	Under review	Yes	Yes	For wood:T: 2-yr D: 1-Yr	T: 307 (100%) D: 2,561 (4.76%)	T: 1 (<1% failure) D: 84 (3.3%)	T: 1D: 84 replaced + 123 (identified &replaced outside the inspection program)	not specified	not specified
Seminole Electric Cooperative, Inc.	Yes	Yes	Not applicable	Not applicable	Not applicable	Transmission Only Company. T: 1-yr	No details	Cross-arm, rot, & insulator. No other details.	No details	NERC Reliability Stds - annual visuals, with scheduled trimming 3-5 yrs	100% of plan
Sumter Electric Cooperative, Inc.	Yes	T: Yes D: 100 mph wind speeds using 2002 NESC	Not applicable. Non coastal utility.	Yes	Yes	T: Climb 5-yr; ground 8-yr. D: Ground inspection of 100% distribution; will be done once every 8-years.	T: 0 (0%) D: 18,357 (14% of total structures)	T: 0 D: 180 (1%) D: 94 (0.5%) ground rot D: 67 (0.4%) top deterioration D: 19 (0.1%) reinforceable	T: 0 D: 180 Replaced or reinforced	D: 3-yr cycle all circuits	100% of plan
Suwannee Valley Electric Cooperative, Inc.	Yes	No	Not applicable. Non coastal utility.	Yes	Yes	Utility inspects all structures every eight years. 8-yr program	T: 5 (100%) D: 8,311 (9.9%). Plans to inspect 10,500 poles (12.6%) in 2008. 100% (5) of transmission is also planned.	T: 0 D: 218 (2.8% of inspections) mostly due to excessive splitting	T: 0 D: 1,563 poles were remediated by ground line treatment	4-yr cycle all circuits	100% of plan
Talquin Electric Cooperative, Inc.	Yes	Guided by 2002 Figure 250-2(d) on or after 12/10/2006.	Under review	Yes	Yes. Agreements under renewal.	T: 1-yr D: 8-yr	T: 199 (1.8% of all poles) D: 10,625 (98.16% of all poles)	T: 0 D: 121 (1.14%) including 15 for decay, 63 rejected poles, and 58 priority poles.	T: 0 D: The priority poles were replaced (58). The rejected poles (63) were inspected and repaired if possible or replaced.	3-yr inspection and trimming cycle	100% of annual plan average

Tri-County Electric Cooperative, Inc.	Not stated	Not stated	Not stated	Not stated	Not stated	T: 303 transmission poles (115 kV) T: 412 transmission poles (69) D: 41,500 distribution poles	T: 668 poles 100% D: 18, 170 poles inspected out of 41,500.	T: 11 (1.6%) D: 886 (4.9%) (No cause statistics)	T: 5 poles have been replaced. The rest will be replaced spring 2008. D: 350 poles have been replaced. The rest are still being worked on.	D: 5-yr trim cycle requiring approx. 600 miles per year 470 miles done in 2007. T: All lines were cleared in 2006 and 2007.	About 90% of annual planned average
West Florida Electric Cooperative Association, Inc.	Yes	Complies with the current edition of the NESC particularly 250c extreme wind loading (with figure 252-2(d) and 250d extreme ice with concurrent wind loading.	WFEC service terr. is approximately 50 mi from coast. A few areas subject to flooding are addressed.	Yes	Yes	Distribution only company. D: RUS Bulletin 1730B-121	Inspected 14% of its system in 2007. No details provided.	6% required maintenance or replacement. No details provided.	6% required maintenance or replacement. No details provided.	One fourth of its distribution system each year.	(No statistics)
Withlachoochee River Electric Cooperative, Inc.	Yes	After 12/10/2006, EWL will be considered.	Yes	Yes. Relocated rear lot lines to the street.	Yes	T: Walking/Riding/Aerial patrol - 100% (1-yr cycle) D: "a considerable portion (4,200 miles out of 6,400 miles) of WREC's system is physically checked annually"	Last pole inspection '04 - Pole inspection program discontinued.	No details provided	No details provided	T: 1-yr cycle D: 5-6 yr cycle	100% of plan (No statistics)

Appendix D. Summary of Municipal Electric Utility Reports

Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2007

Utility	The extent to which Standards of Construction address:						Transmission & Distribution Facility Inspections				Vegetation Management	
	Comply with the 2007 NESC on or after 2/1/2007	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG & OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity, and engineering standards for Attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection.	Number and percent of poles and structures planned & completed	Number and percent of poles and structures failing inspection with reasons	Number and percent of poles and structures, by class, replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation.	Quantify, level, and scope planned and completed for transmission and distribution.
		Major Planned Work, Expansion, Rebuild, or Relocation	Targeted Critical Infrastructure and major thoroughfares									
Alachua, City of	Yes	Follows 2002 NESC 250.C		100-yr flood plain in design standards.	Yes	Yes	Distribution only. 8-yr cycle 12.5% annually	2773 total poles in 2007 Inspected: 126 (5.5% of system)	1 (0.8%) Ground and pole decay	1 @ 50 ft. Class 3 replaced	D: The City of Alachua trims the overhead distribution system on a yearly cycle. City has 130 miles of distribution system and trimmed 3% in 2007.	None specified
Bartow, City of	Not yet but under review. Yes after June 2008	Not guided		Not applicable. Not located in coastal area.	Yes	Yes	Not reported	D: 300 inspections (2.5% of system)	40 poles failed, rot and decay.	All bad poles were replaced.	D: 4-yr cycle all circuits. 6-10 ft clearances	None specified
Beaches Energy Services	Yes	120 mph for structures 60 ft. & taller - 2002 Figure 250-2(d)		Yes	Yes. For example back-lot line has been eliminated.	Yes	T: Has only 138kv transmission circuits (spun or cast concrete poles or monotube steel poles) 1-yr cycle D: 8-yr (sound bore)	T: 100% (355) D: 100% (4657)	T: None D: 164 or 3.5%	T: None D: All 164 have been or are being replaced.	T: NERC Reliability Standards FAC-003-1 D: Average 2-3-yr cycle all circuits.	100% of plan

Blountstown, City of	Yes	No. Will continue to examine this issue in 2008.	No UG facilities. No further discussion.	Yes	No	Distribution only company. 100% visual 1-yr	1,693 (100%)	10 (0.6%) rot and clearance - no specifics	10 replaced	D: 4-yr trimming cycle all circuits with 10 ft. clearance in 2008.	100% of plan
Bushnell, City of	Yes	Guided by 2002 Figure 250-2(d)	No infrastructure located in coastal communities.	Yes. Back-lot lines or in accessible areas are not allowed.	Began inspecting poles and attachments in 2007.	Distribution only facilities. Started program in 2007. 100% 3-yr cycle	305 inspected (32% of entire system)	16 poles failed (5% of inspected), rot and decay	5 (31%) have been replaced	1-yr cycle with cut-back to 3-yr growth levels. Avg. clearance not stated.	Not specified
Chattahoochee, City of	Yes	Guided by 2002 Figure 250-2(d)	Not applicable; not a coastal community.	Yes. Existing inaccessible distribution facility will be moved.	Yes	Distribution Only Company. D: 3-yr cycle	1,957 (100% of system inspected in 2006)	47 (2.4%) defective, decay and animal damage	24 replaced in 2006; 12 replaced in 2007; 12 poles are to be replaced in 2008	D: 1-yr cycle all circuits.	100% of plan
Clewiston Utilities, City of	Yes	Will comply with the NESC extreme wind loading in effect at the time of design. No details.	Not applicable. Located 60 miles from either coast.	Yes. New residential are front-lot.	None specified	D: 8-yr cycle. Will complete within 4-yrs.	25% of poles inspected in 2007; 25% will be inspected in 2008 and for the following two years, then continue on 8-yr cycle	31 poles (10.7%), rot and decay	All 31 rejected poles will be replaced or remediated with a steel truss in 2008.	D: 1-yr cycle all circuits.	100% of plan
Fort Meade, City of	Yes	Guided by 2002 Figure 250-2(d) on or after 12/10/2006.	Yes	Yes	Yes	Distribution only company. D: 8-yr inspection program.	342 poles out of 2725 poles were inspected for 2007	7 (0.3% of all poles)	36 poles were replaced in 2007.	D: 3-yr trimming program	33% of system trimming has been completed

Fort Pierce Utilities Authority	Yes	Not guided on a system-wide basis but guided by NESC 2007 standard of 150 mph for new construction, Targeted critical infrastructure and major planned work/relocation of existing facilities after 2/1/2007.	Yes	Yes	Yes. Attachments are on an 8-yr cycle inspection.	T: 250 wood poles 1-yr 106 concrete and 90 steel 3-yr D: 8-yr (starts May 2008)	T: 100% of system in 2007 D: No data (first inspection is in mid-May 2008)	T: None D: None	Not applicable	T: 3-yr cycle D: 3-yr cycle all circuits	100% of plan
Gainesville Regional Utilities	Yes	Guided by 2002 Figure 250-2(d) on or after 12/10/2006.	Not subject to storm surges and have limited exposure to flooding.	Yes	Yes	T: visual 2-yr, wood poles 8-yr, all else 3-yr D: 8-yr	T: 164, 100% of plan D: 2,854, 100% of plan	T: 2 (1.2%) woodpecker D: 28 (1.0%) (shell rot, decay, split pole top, and carpenter ants.	T: 2 D: 28 replaced; class data provided	T: NERC Reliability Standars FAC-003-1 (6-yr cycle) D: 3-yr cycle	100% of plan
Green Cove Springs, City of	Yes	Guided by 2002 Figure 250-2(d)	Yes	Yes	Yes	Distribution only company. D: 8-yr program under development	No details	D: 6 (0.20% of installed infrastructure)	D: 1 concrete pole replaced (wind impact); 6 wooden poles replaced due to rot.	D: 1-yr cycle all circuits	100% of plan
Havana, Town of	Yes	Not considered	No flooding issues.	Yes	Under review in 2008.	Distribution only company. D: 1-yr informal, program under development.	No details	A section of transmission lines; age	500ft of 3-phase overhead electrical transmission line was replaced.	D: 1-yr cycle all circuits	Not specified
Homestead, City of	Yes	Guided by 2002 Figure 250-2(d) on or after 12/10/2006.	Yes	Yes. All new residential services are in the front lot and are underground.	Yes	T: All poles are concrete D: Intent is to inspect 800 distribution poles. 8-yr program under development.	T: 100% of system inspected in 2005; 0% in 2007 D: Plan to inspect 12.5% of total poles per year.	0	0	T: Not Reported D: estimated 2-yr cycle all circuits with 6 ft. clearance.	No plans have been completed yet except 100% of transmission inspected in 2005.

JEA	Yes	120 mph for structures 60 ft. and taller, as guided by figure 250-2(d) in the 2002 edition of NESC	Very little flooding experience; nothing written.	Yes. Abandoned rear entrance facilities, has not constructed rear entrance facilities in over 30-Yrs.	Yes	T: 2-4-Yr (30 circuits per year) D: 1/8 is done annually (sound bore & excavate) D: laterals w/ more than 3 outages / 90 days.	T: 10 of 30 circuits were completed in 2007 (33.3%) D: 6 of 40 circuits in Feb 2007 (1/8th)	T: 7 wood- 0.5% ground line decay and 4 steel mono-poles (0.3%) failing for minor damage. D: 6% of poles are failing; 60% of failures ground line decay; 40% pole top decay	No detailed class data. T: 100% of decayed poles replaced (7). D: 56% of rejected poles (418) have been replaced. The others not rejected are ground treated.	T: NERC Reliability Standards FAC-003-1 2.5-yr trim cycle started in 2007	100% of plan
Keys Energy Services	Yes	Complies with 2007 NESC extreme wind load.	Yes	Yes	Yes	T: Visual/infrared 2-yr cycle, structures 4-yrs. D: Inspection freq. not specified but all poles were inspected by May 2007.	2006 not reported. 100% inspection completed in May 2007	T: 0 D: 2250 poles (20.3 %) exceeded standards for decay & acceptance	Replacement: 274 in '07; 800 in '08	T: NERC Reliability Standards FAC-003-1 D: 2-yr cycle all circuits.	100% of plan
Kissimmee Utility Authority	Yes	Guided by 2002 Figure 250-2(d) on or after 12/20/2006.	Very little flooding experience; nothing written	Yes. No back-lot for a number of years.	Yes	T: Visual 1-yr, infrared 1-yr. D: Infrared 1-yr; visual 5-yrs, 8-yr for wooden; excavate for poles over 10-yrs old.	T: 207 wood D: Visual 5-yrs 170 circuit miles (20%); 2000 scheduled for 2007 based on 8-yr plan. 5742 were actually inspected.	T: 5(2.4%) (heart rot, pocket, decay) D: 79 (1.4%) (shell rot, rotten butt)	T: 5 D: 7 replaced, plan to restore 52 and replace 19	T: NERC Reliability Standards FAC-003-1 (1-yr cycle) D: 3-yr cycle all circuits.	100% of plan
Lake Worth Utilities Dept.	Yes	Not designed to be guided by the extreme loading standards on a system wide basis.	Underground: Yes; Nothing for overhead.	Yes	Implied in construction standards, policies, and guidelines. No statement of distinct written document.	T: Visual 1-yr. D: Visual 2-3-yrs	No formal program in 2006.	No data	No additional data.	T: 2-yr cycle D: 2-yr cycle.	100% of plan

Lakeland Electric	Yes	Grade B with extreme wind loads applied guided by 2002 Figure 250-2(d) on or after 12/10/2006.	Very little flooding experience. Not a coastal area.	Yes. Back-lot discontinued over 25-years.	Yes	No formal or cyclical program, but there are plans to inspect all wooden poles on an 8-yr cycle (initiated in 2007)	T: 200 planned (17%) 231 inspected (19.7%) D: 10,000 planned (16.7%), 13,439 inspected (22.3%)	T: 4 poles (1.7%) due to decay D: 256 poles (1.9%) due to decay	T: All 4 poles are having work orders written for replacement this year. D: 6 poles have been replaced and 37 poles will be reinforced with struts before June 2008.	T: 3-yr cycle D: 4-yr cycle all circuits.	100% of plan
Leesburg, City of	Yes	Guided by 2002 Figure 250-2(d)	No. Not subject to major flooding or storm surge. 60 miles inland from Atlantic and Gulf coasts	Yes	Yes	Distribution only company. 8-yr inspection cycle	D: 6220 poles inspected	163	163 (2.62%)	4-yr trim cycle for all circuits.	100% of plan
Moore Haven, City of	Yes	Engineering is outsourced. No in-house formal standards.	No flooding in the area. Non coastal community.	Yes	None	No formal document. Distribution only. Visual 1-yr	100%	0	5 poles replaced during relocation of distribution, wires from easements to right of ways to obtain easier access.	D: 1-yr cycle all circuits.	100% of plan
Mount Dora, City of	No. The City plans to make effort to comply this year.	No written standards.	No flooding in the area.	Yes. Back-lot is not allowed.	None	No formal document or program. Distribution only. Routinely makes a visual inspection of the 6 feeders.	No data	No data	No data	D: 1-yr cycle all 6 feeders.	Not applicable/ not reported
New Smyrna Beach	Yes	Yes, on or after 12/10/2006.	Yes	Yes	Yes	T: 4-5-yrs. D: 7-9-yr (sound & spike)	T: 100 (25%) D: 600 (6%)	T: 0 (0%) D: 26 (4%)	T: 0 D: 26 replaced.	No set cycles.	T: 20% D: 20%

Newberry, City of	Yes	Guided by 2002 Figure 250-2(d) on or after 1/1/2007.	Not Applicable. Located 45 miles from coastal area.	Yes. Rear-lot not allowed.	Under review	Distribution only D: 3-yr	D: 1,007 (100%) in 2006. They will be inspected again in 2009. None inspected in 2007.	In 2006, 73 poles (7%) were defective. In 2007, no poles were inspected in 2007.	28 (38% of failed poles-class 5, 45' wood poles, replaced in 2007) 2 (3% class 5, 35' wood poles were replaced in 2007) 7(10% class 5, 30' wood poles, replaced in 2007)	D: 3-yr cycle all circuits.	100% of plan
Ocala Electric Utility	Yes	No written wind load standards for distribution.	Not applicable. Not located in coastal area.	Yes	Yes	T: Wood 8-yr (12.5% inspection cycle of system) D: Wood 8-yr	T: 672 (100%) D: 2,056 (7.2%) Did not meet goal of 12.5% b/c of focus on completing transmission poles	T: 35 rejected (5.2% reject rate) D: 180 rejected (7.1% reject rate)	T: 23 poles restored and 12 replaced D: 80 poles restored and 100 replaced	T: 3-yr trim cycle D: 3-yr cycle.	100% of plan
Orlando Utilities Commission & City of St. Cloud	Yes	Guided by 2002 Figure 250-2(d)	Not applicable. Located in the middle of Florida.	Yes	Yes	T: wood 8-yrs. + annual inspection of essential distribution and transmission equipment. D: 8-yr.	No T&D details; planned 6,400 (12.5%); completed 8,124 (16%)	No T&D details, 226 (2.7%) decay	Replaced 82 in 2007. Will replace remaining 144 in 2008.	T: Urban 1-yr Rural 3-yr D: 4-yr cycle	Over 100% of plan
Quincy, City of	Yes	Guided by 2002 Figure 250-2(d) on or after 12/10/2006.	Not applicable	Yes	Under review	Monthly drive by patrols. New 8-yr program beginning 2007.	T: 31 concrete (100%) D: 2,842 wood (100%)	T: 0 D: 2 (0.07%) Pole damage and rot.	Replaced 2.	T: not stated separately D: 4-yr cycle all circuits.	100% of plan
Reedy Creek Improvement District	Yes	Guided by 2002 Figure 250-2(d) on or after 12/10/2006.	Not applicable. Located in Central Florida away from the coast.	Yes	No attachments	T: 69 KV 5 wooden poles (2-yrs) Concrete/steel D: 12.5 KV (Underground system) 13 wooden poles (2-yr) remainder on concrete/steel	T: 5 D: 13	T: None specified. Wooden poles were last treated in 2006 D: Not specified.	T: None specified D: None specified	T: Tree trimming (1-yr) each spring	90% of plan (rights of way)

Starke, City of	Yes	Guided by 2002 Figure 250-2(d) on or after 1/1/2007.	Not applicable. Inland community.	Yes. Rear-lot not allowed.	Under review	Annual visual inspections. No details re: T&D.	3,389 (100%)	87 (2.6%) 55 poles bad 14 splitting/ animal contact; 18 new-replacements for upgrade	All 87 poles were replaced in 2007.	T: Not stated separately. City has annual tree trimming and vegetation contract with Gainesville Regional Utilities to provide 12 wks of annual tree trimming.	100% of plan. Will do 33% in 2008.
Tallahassee, City of	Yes	Guided by 2007 edition of Figure 250-2(d)	Not applicable. Not a coastal community.	Yes. Rear-lot not allowed.	Yes	T: 5-yrs. D: Wooden poles 8-Yrs.	T: 3,006 D: 46,191	T: 3006 poles inspected D: 45833 poles inspected	T: 8 replaced (0.27% of poles inspected) D: all 275 faulty poles were finally replaced in 2007	18-month cycle	100% of plan
Vero Beach, City of	Yes	Guided by 2002 Figure 250-2(d) since 2005.	Yes.	Yes	Yes	T: Visual 2-3-month cycle. D: One 5-Yr cycle (sound & bore) over 20-yrs or visual evidence. Plans are to inspect 1000 to 1250 poles per year.	T: 4 visual inspection cycles (500%). All poles inspected D: 30% (1794)	T: 0 D: 34 failures (1.9%)	T: 0 D: Replaced	T: Not discussed D: 3-yr cycle	100% of plan
Wauchula, City of	Has standards in place but did not specify which.	Follows NESC standards for extreme wind loading. Doesn't specify year.	Not applicable. 60 miles from Atlantic and Gulf coast.	Able to access distribution facilities on or behind customer's property.	Under review. No standards in place at this time.	1/3 of all lines completed in 2007. No further details on T or D.	No details (1/3)	Less than 1% out of 1800 poles. Failure due to poles rotting at ground line.	1 of their 5 transmission poles was replaced.	Tree trimming 1/3 per year. No details.	100% of plan
Williston, City of	Yes	Guided by 2002 Figure 250-2(d) on or after 12/10/2007.	Not applicable. Located 45 miles away from coast.	Yes. Rear-lot not allowed.	Under review	Distribution only D: 3-yr cycle	33%	5 (1.75%) wood decay/below ground level	5 poles replaced	T: Not discussed D: 3-yr cycle	100% of plan

Winter Park, City of	Yes	Not designed to be guided by the extreme loading standards. "The city has begun an ambitious initiative to put its entire distribution system underground."	Not applicable. Non-coastal community.	Yes	Negotiating with other utilities on a joint use agreement.	Distribution only D: Policy being drafted to meet 8-yrs or 12.5% per year.	No system wide sound and bore testing has been completed to date. However, the city has plans to begin sound and bore testing in 2008.	The City of Winter Park has not done a formal inspection of all its distribution poles in 2007.	The City of Winter Park has not done a formal sound and bore inspection of all its distribution poles in 2007.	3-yr trim cycle.	100% of plan