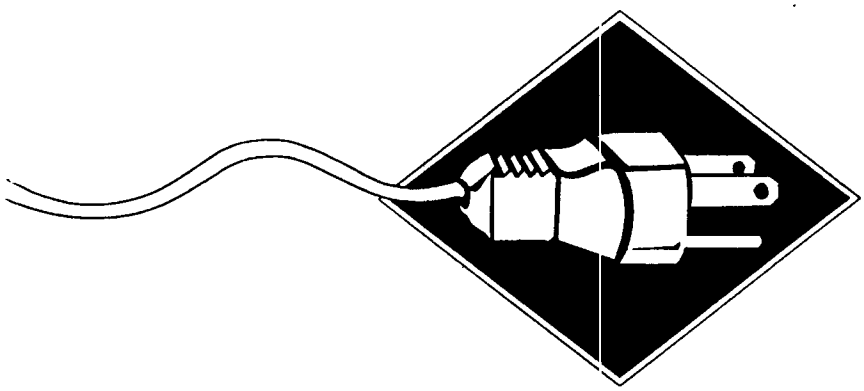
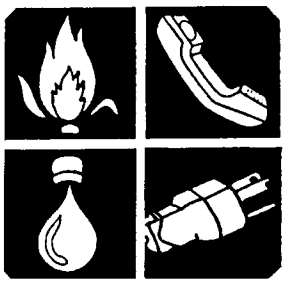


Preliminary Review of

Vegetation Management, Lightning Protection, and Pole Inspection at Progress Energy of Florida, Incorporated

July 2005

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



1.0 Background

1.1 Objectives

This preliminary review of Progress Energy Florida (Progress Energy, PEF, or the company) was conducted on behalf of the Florida Public Service Commission (FPSC or the Commission) by the Bureau of Regulatory Review (BRR) of the Division of Competitive Market and Enforcement. The review, along with four others, was requested by the Division of Economic Regulation to learn more about each Florida investor-owned electric utility company's efforts to maintain and improve distribution and transmission service reliability during the period 1999 through 2004. The review objectives were as follows:

- To provide an update of reliability information originally gathered through the reliability review reports published in December 1997 and November 2000,

- To document and evaluate any changes in corporate philosophy; company organizational structure; operational procedures; monitoring and measurement systems; and capabilities impacting electric service quality and reliability, and

- To document and evaluate electric utility activities and programs of improvement for distribution and transmission facilities during the period 1999 through 2004.

1.2 Scope

This review specifically examined Progress Energy's approach to protecting its system and its customers against three outage causes: vegetation, lightning, and pole failure. The scope for this preliminary review was limited to these three focus areas to allow for timely completion of the review for use in the company's pending rate increase proceeding. Staff plans to complete the full reliability review of Progress Energy at a later date.

The review encompasses the period 1999 through 2004 and the company reliability results, programs, and improvement efforts during that period. To an extent, it documents current plans as reflected in 2005 budget data. This report examines relevant data and information in order to determine whether reliability in each of the three focus areas changed over the period 1999-2004. To do so, staff focused on the following data and sources:

- Written company procedures
- Annual Reliability Reports filed with the FPSC
- Company-monitored reliability data
- Company internal audit reports

1.3 Methodology

BRR staff analyzed reliability performance indices and trended company performance during the review period. Staff also requested and reviewed company documents pertaining to Progress Energy distribution and transmission improvement programs and activities. In-person and teleconference interviews were conducted with company managers to better understand procedures, processes, systems, and improvement efforts for each focus area. Particular attention was paid to improvement program objectives, measurements, budgets, performance results, and changes in utility practices and philosophies that may have impacted service during the study period.

1.4 Reliability Results

The table below show Progress Energy's distribution reliability performance for system average interruption duration, system average interruption frequency, and customer average interruption duration during the period 1999 through 2004. These and other indices are used by the company and the Florida Public Service Commission to assess overall reliability performance. These performance indices have also been provided for each of the specific focus areas reviewed.

Overall Company Distribution Reliability Results				
Year	Number of Interruptions	SAIDI[1]	CAIDI[2]	SAIFI[3]
1999	38,900	97.0	71.8	1.35
2000	38,986	100.6	75.4	1.33
2001	38,939	89.7	68.7	1.30
2002	40,193	88.0	70.1	1.26
2003	41,873	85.8	67.7	1.27
2004	38,249	77.0	64.7	1.19
Distribution Vegetation Reliability Results				
1999	4,776	14.7	74.0	0.20
2000	5,926	21.4	79.5	0.27
2001	5,932	19.9	75.0	0.27
2002	7,013	20.2	74.5	0.27
2003	8,141	22.2	69.5	0.32
2004	6,793	16.7	68.6	0.24
Distribution Lightning Reliability Results				
1999	3,188	8.8	87.6	0.10
2000	3,523	9.1	85.0	0.11
2001	4,485	10.2	82.0	0.12
2002	2,146	5.1	75.2	0.07
2003	1,103	4.5	70.9	0.06
2004	2,287	4.6	73.0	0.06
Distribution Pole Failure Reliability Results				
1999	2	0.0827	189.3	0.00044
2000	0	0.0000	00.0	0.00000
2001	7	0.0324	181.8	0.00018
2002	4	0.0014	149.1	0.00001
2003	2	0.0002	41.7	0.00001
2004	1	0.0005	149.0	0.000003

Table 1

1.5 Overall Opinion

Based on a focused review of the three functional areas of vegetation management, lightning protection and pole inspections, staff's overall opinion for each area is provided below. Staff findings related to vegetation and pole inspections are described in greater detail in section *5.0 Conclusions.*

1.5.1 Vegetation

The company has experienced an increase in overall vegetation-caused interruptions during the review period. Along with an increase in outages, the number of customer interruptions due to vegetation outages has increased. Staff notes that the number of miles of feeder lines trimmed has declined during the same period.

1.5.2 Lightning

Progress Energy's number of interruptions caused by lightning has declined during the review period. The company has decreased the impact of lightning-related outages, as can be seen in the 2001 through 2004 lightning reliability results.

1.5.2 Pole Inspections

The company has not experienced a large number of interruptions related to pole failure during the review period. The company does have procedures and guidelines for conducting both distribution and transmission pole and facility inspections. While the company has conducted inspections during the review period, staff notes the company has not maintained its inspection schedule as outlined by management.

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[1] SAIDI - System Average Interruption Duration Index.
[2] CAIDI - Customer Average Interruption Duration Index.
[3] SAIFI - System Average Interruption Frequency Index.

2.0 Vegetation Management

2.1 Programs and Controls

Progress Energy's vegetation-related outages are controlled primarily by the use of tree-trimming contractors who systematically remove branches, vines, and entire trees that encroach within defined distances of the company's lines and poles. For both its distribution and transmission facilities, these trimming activities are overseen by Progress Energy's foresters and employees who oversee and direct the contractors' work. The goal of Progress Energy's vegetation management program is to minimize vegetation-caused reliability events in the most cost-effective manner while improving customer satisfaction.

2.1.1 Distribution

The distribution vegetation director and company forester are located in North Carolina. The company forester oversees two regional state foresters located in Florida. Together, they determine what work needs to be performed by the vegetation trimming contractors. The company uses combinations of cycle, demand, and single job trimming for its distribution vegetation clearing. Cycle trimming includes the scheduled feeder and branch-line trimming completed during a set period. Demand trimming involves the removal of vegetation in a given area outside the normal trimming cycle. Single job trimming includes any one-time work such as new construction projects.

The contractors provide written weekly reports to the forester and regional management updating the company on the progress of the work. These reports are used by the foresters to monitor the status of the vegetation trimming in each area. The company targets a three-year distribution cycle for its feeders and branch-line work.

On a regional basis, the contractors' work performance is evaluated by 12 Progress Energy contract inspectors who monitor both line construction and vegetation work. These contract inspectors monitor, evaluate, and document the trim work and note any deficiencies. The inspectors' reports are compiled in a database for review by two regional inspection supervisors. If a deficiency or problem is detected, the contract crew is responsible for correcting the situation at its own cost. If there is an ongoing problem, the Distribution Asset Operations group becomes involved in the resolution process.

The internal audit department evaluates and reviews the trimming programs for performance and overall risks. During the review period, the company's internal audit department conducted reviews and audits of the vegetation-trimming process, the distribution contractor inspection processes, and the contract management process. The audit department made observations and recommendations in these areas including enhancing the contractor work inspection procedures, clarifying the role of inspection staff, and increasing the resources of the contract inspection group. All recommendations were implemented and are now closed.

A reorganization of the company's distribution workforce is being implemented during 2005. Oversight responsibility for the distribution vegetation management operations for the state will be decentralized from North Carolina to Florida into the restructured Distribution Asset group. The company will add a project manager/state forester to oversee an anticipated staff of four foresters. The additional staff to be added as a result of the proposed budget changes should enable Progress Energy to be more effective at managing its vegetation-control programs.

2.1.2 Transmission

The transmission vegetation management program has been strengthened since the merger between Carolina Power and Light (CP&L) and Florida Power Corporation (FPC). Prior to the merger, the company only conducted reactionary transmission trimming. Starting in 2002, the company transitioned to a four-year trim cycle. Additionally, the company began conducting aerial inspections three times per year to monitor vegetation growth along its transmission lines. The company greatly increased its expenditures to accomplish the increased workload.

This renewed focus on transmission vegetation management began when the company conducted an internal study on its transmission vegetation management practices in 2002. The study outlined the differences in the transmission vegetation management approaches between CP&L and FPC. The CP&L guidelines, which required more stringent trimming, were adopted into the Progress Energy Florida procedures. With the incorporation of the CP&L guidelines, the Florida transmission unit has been focusing on reclaiming and trimming all authorized rights-of-way throughout its territories.

Transmission vegetation management is overseen by the Transmission Construction group. Starting in 2002, a state-wide forester began overseeing four regional foresters who determine and target the trimming needs for the state. These regional foresters direct the trim contractors regarding work that needs to be performed in each region. The regional foresters also monitor and evaluate the contractors' work performance. In addition to the regional foresters, the company uses a third-party contractor to monitor and evaluate the tree contractors' performance.

The tree contractors submit weekly reports to the foresters and regional management outlining the progress of trim work within each cycle area. These reports are used by management to monitor the status of the vegetation trimming in each area. If there is an ongoing problem with the contractors' performance, the Transmission Construction group which oversees the contracts, becomes involved in the resolution process.

2.1.3 Vegetation Contracts

The transmission vegetation maintenance contracts contain work expectations and trim guidelines for the contractors. The contracts outline performance quality parameters and price per unit charges. The company currently uses two contractors for distribution trimming and three for transmission trimming. The transmission and distribution units have separate contracts with each of their vendors. All contracts are three years in length with Progress Energy conducting annual evaluations of contractors' work.

2.2 Budgets and Expenditures

2.2.1 Distribution

Between 1999 and 2004, the company increased the dollars spent on distribution vegetation management. Between 2001 and 2002, the company increased its expenditures by 39 percent. The company spent $9,900,000 in 1999; $9,600,000 in 2000; $9,500,000 in 2001; $13,216,000 in 2002; $14,521,000 in 2003; and $15,409,000 in 2004. The 2005 budget for distribution vegetation management is $13,977,777.

During the review period, the company allocated extra funding under its Commitment to Excellence (CTE) program. This effort targeted specific reliability improvement programs to reduce the duration of service interruptions. In distribution, the actual dollars spent under the CTE program were $1,609,000 in 2002; $599,000 in 2003; and $1,902,000 in 2004. This company-wide program ended in 2004 and the 2005 overall vegetation budget reflects the absence of these funds.

While vegetation spending has increased during the review period, the company's distribution cost per mile has also increased. The dollar cost per mile (excluding CTE dollars and demand trimming expenditures) were $1,686 in 1999; $1,620 in 2000; $1,845 in 2001; $1,808 in 2002; $2,819 in 2003; and $2,907 in 2004. The 2003 and 2004 expenditures reflect the higher cost that resulted from the renegotiated trimming contracts. Overall, the company has trimmed fewer miles and feeders during the 2002 through 2004 period, as compared to 1999 through 2001.

2.2.2 Transmission

Transmission vegetation management expenditures have increased significantly during 2002 through 2004 versus the 1999 through 2001 period. Dollars spent each year were $967,711 in 1999; $1,446,450 in 2000; $896,348 in 2001; $5,122,350 in 2002; $5,845,714 in 2003; and $5,233,979 in 2004. This reflects the adoption of more stringent trimming standards after the merger. The budget for 2005 is $3,560,870. The increase in spending from 1999 to 2004 was 440 percent. The number of transmission miles trimmed per year has not increased significantly over the review period. Rather, the company states the trimming performed since 2002 consists of more vegetation removal per mile than the previous years as a result of adopting more rigorous standards after the 2002 transmission vegetation study.

2.3 Reliability Results

Overall, the number of distribution vegetation outages and the system average interruption duration associated with vegetation outages have increased during the review period. Since 2000, vegetation has been the leading cause of outages for Progress Energy. Progress Energy subcategorizes its vegetation outages into two categories: Tree-Preventable and Tree-Non-preventable. An outage categorized as Tree-Preventable is defined as being caused by vegetation within the specified trim zone for the company facility. An outage categorized as Tree-Non-preventable is one that could not be avoided, such as a tree falling from outside the company's right-of-way or trim zone. These two subcategories are combined to determine the

company's overall vegetation outage results. The company experienced its highest number of vegetation-caused outages in 2003, when they totaled 70 percent more than its 1999 level of outages. The numbers of outages attributed to vegetation annually were 4,776 in 1999; 5,926 in 2000; 5,932 in 2001; 7,013 in 2002; 8,141 in 2003; and 6,793 in 2004.

While the company reported its 2004 SAIDI results have improved to 77 minutes, the minutes of SAIDI attributed to vegetation during the review period have increased both for overall vegetation outages and for the subcategory of Tree-Preventable. The SAIDI minutes attributed to total vegetation outages annually were 14.73 minutes in 1999, 21.43 minutes in 2000, 19.90 minutes in 2001, 20.22 minutes in 2002, 22.20 minutes in 2003, and 16.65 minutes in 2004. The minutes of SAIDI attributed to Tree-Preventable outages were 6.18 minutes in 1999, 8.45 minutes in 2000, 8.65 minutes in 2001, 9.28 minutes in 2002, 12.51 minutes in 2003, and 10.83 minutes in 2004. While there was a decrease in average Tree-Preventable interruption duration of 1.68 minutes from 2003 to 2004, during 2004 the company still experienced the second-highest number of minutes during the review period. Staff notes that during 2004, as a result of four hurricanes affecting Progress Energy's service territory, a large number of outages were excluded under FPSC reporting guidelines. **Table 2** details the vegetation SAIDI results.

Progress Energy Distribution Vegetation Indices				
Year	**Number of Vegetation-Caused Outages**	**Number of Vegetation-Caused Customer Interruptions**	**SAIDI attributed to Overall Vegetation**	**SAIDI attributed to Preventable Vegetation**
1999	4,776	273,007	14.73	6.18
2000	5,926	375,935	21.43	8.45
2001	5,932	380,597	19.90	8.65
2002	7,013	400,677	20.22	9.28
2003	8,141	482,343	20.20	12.51
2004	6,793	373,897	16.65	10.83

Table 2

While the number of vegetation-caused outages has increased during the review period, both the number of distribution miles trimmed and the number of feeders trimmed have decreased. Progress Energy management states that the company is on a targeted three-year trim cycle. When looking at the three-year cycles from 1999 through 2004, the company has trimmed successively fewer miles of line. For the period 1999 through 2001, the company trimmed a total of 16,944 miles of line as compared to 2002 through 2004, when the company trimmed a total of 12,879 miles of line. Also for the same periods, the company trimmed 1,015 feeders in 1999 through 2001, while only trimming 682 feeders for the 2002 through 2004 period. The company has approximately 1,100 feeders consisting of 18,117 miles of overhead primary and 6,675 miles of overhead secondary lines in service. **Table 3** details Progress Energy's trimming for the review period.

Progress Energy Distribution Vegetation Miles/Feeders Trimmed Annually				
Year	**Number of Feeders Trimmed**	**Number of Feeder Miles Trimmed**	**Company Total OH[1] Feeder Miles**	**Trimming Cost Per Mile**
1999	305	5,871	*Not Available*	$1,686
2000	452	5,924	16,461	$1,620
2001	258	5,149	17,962	$1,845
2002	286	5,214	17,912	$1,808
2003	162	3,665	18,028	$2,819
2004	234	4,000	18,117	$2,907

Table 3

[1] OH- Overhead Primary

3.0 Lightning Protection

3.1 Programs and Controls

Lightning protection is provided through the basic system design and components of Progress Energy's facilities. The distribution and transmission linemen inspect lightning protection equipment during cyclical ground facility inspections. Transmission linemen also inspect static wires during periodic aerial inspections. Substation lightning protection is inspected and infrared tested during monthly substation inspections. All lightning inspections and maintenance are conducted by Progress Energy employees.

Lightning protection is the responsibility of the operation and maintenance division and the engineering division. The company has maintained a stable workforce size within the operations and maintenance divisions for transmission and distribution. In 2003 and 2004, a small staff implemented the portions of the Commitment to Excellence (CTE) program related to lightning protection. This was a temporary program primarily focused on improving the company's SAIDI index. This CTE group focused its efforts on replacing and adding lightning arresters to areas that had experienced high numbers of lightning outages. The goal of Progress Energy's lightning protection program is to improve its reliability indices by maintaining and improving the lightning protections within its system.

3.1.1 Distribution

The distribution system's main lightning protection is arresters that divert lightning-caused surges away from system components. The lightning protection design and placement is under the Distribution Assets group and the senior engineer. This group monitors the lightning patterns and strikes in the service territory to better target lightning protection efforts. The regional managers and their staffs are in charge of the inspection and maintenance of the equipment under the normal maintenance program.

In 2002, the company placed greater emphasis on lightning arrester replacement under the CTE initiative. The company allocated extra funding for this focus area. This initiative was completed in 2004. In 2005, the focus has changed to include lightning as part of the Distribution Assets group's "poor-performing feeders" initiative.

This poor performing feeder initiative started by targeting the company's least-performing feeders to update and improve the feeders' equipment. During 2005 through 2009, the company will be completing approximately 220 feeders each year until the entire distribution feeder system has been updated. Along with the targeted initiatives of CTE and poor-performing feeders, the company conducts routine maintenance facility inspections of its distribution lines. These are conducted on a five-year cycle. These inspections monitor the overall quality of the facilities, including the condition of the lightning arresters.

The 2005 reorganization effort will allow the oversight of lightning protection efforts to be more centralized under the Distribution Asset group. The new structure will assign project managers to assist regional managers on lightning-related maintenance issues.

3.1.2 Transmission

The company's transmission system uses overhead static wire as its main form of lighting protection. Substations are equipped with terminal pole and arrester protections. The lightning protection design and placement is a responsibility of the transmission engineering group. The overall maintenance and performance is the responsibility of the transmission regional managers and their staffs. The regional staff monitor the effectiveness of the lightning protection on the lines and substations. The 2005 reorganization will create a Transmission Asset Management group. As part of its responsibility, the group will plan and design the overall lightning protection initiatives.

During the review period, the company placed emphasis on updating certain components of its lightning protection and prevention. For instance, the company has replaced silicone carbide arresters with metal-oxide varistor surge arresters in substations. The company has also added lightning arresters together with SF6 circuit breakers for better protection. The company uses a mapping system to overlay lightning stroke data for monitoring while incorporating data from the National Lightning Detection Network. Along with these changes, the company has added digital fault recorders to more accurately determine transmission line fault parameters from lightning outages.

3.2 Budgets and Expenditures

Lightning protection is integrated into the distribution and transmission maintenance budgets. The distribution group placed extra budget dollars earmarked for lightning protection in 2003 and 2004 under the CTE program. In 2003, the company budgeted $293,000 and spent $429,000. In 2004, the company budgeted $615,000 and spent $273,000. The focus was to replace failed arresters and to add more arresters in high strike areas. The company's expenditures in 2003 were higher due to more repairs being needed after the high lightning stroke year of 2002 damaged more equipment. The 2004 expenditures were lower due to delays caused by the 2004 storm season. For 2005, the company has not allotted any specific funding to lightning.

Transmission lightning protection is budgeted as part of the proactive repair of transmission structures. Expenditures were $441,036 in 2002; $1,341,268 in 2003; and $1,726,425 in 2004. The increase in spending during 2003 and 2004 was for CTE initiatives. Also, the company states that capital dollars were also used on a project-by-project basis to update its transmission lightning protection equipment.

3.3 Reliability Results

Lightning outages have been on a downward trend during the review period. The company experienced its largest number of lightning-caused outages in 2001 and experienced a

decrease in the number of events during 2002 and 2003. The number of lightning outages increased in 2004, but the number of outage events was fewer than the number recorded annually in 1999 through 2001. The company also tracks lightning stroke data for its territory and notes that the years 2003 and 2004 had the highest total stroke counts during the review period.

The company has reduced its SAIDI attributed to lightning outages during the later part of the review period. The number of SAIDI minutes attributed to lighting outages were 8.80 in 1999, 9.09 in 2000, 10.22 in 2001, 5.13 in 2002, 4.53 in 2003, and 4.59 in 2004. The SAIDI minutes attributed to lightning outages peaked in 2001 and has decreased during 2002 through 2004. **Table 4** details Progress Energy's lightning results for the review period. Overall, the company appears to have met its goals of improving its lightning-related reliability indices during the review period.

Progress Energy Distribution Lightning Results			
Year	**Number of Lightning-Caused Outages**	**Number of Lightning-Caused Customer Interruptions**	**SAIDI attributed to Lightning**
1999	3,188	137,720	8.80
2000	3,523	149,257	9.09
2001	4,485	178,889	10.22
2002	2,146	100,752	5.13
2003	1,103	96,376	4.53
2004	2,287	96,973	4.59

Table 4

4.0 Pole Inspections

4.1 Programs and Controls

The overall pole inspection objective for the company is to improve its reliability results by conducting inspections that detect and treat decay and mechanical damage to poles. The company conducts two different type of inspections on its pole facilities—ground-line excavation and ground patrol. The ground-line excavation inspections are conducted by contracted companies to evaluate the structural integrity of wood poles through a sounding and boring process. The ground patrol inspections are completed by Progress Energy linemen who monitor the overall maintenance conditions of the pole and its attached components.

4.1.1 Ground-Line Pole Inspections

Ground-line inspections are conducted by contractors who specifically monitor and evaluate the structural quality of the wood poles and the extent of decay for each pole. The contractors inspect the quality of the poles and determine whether fumigant treatment, bracing, or replacement are needed. The wood pole quality inspections are planned on a 10-year cycle for both transmission and distribution. After each pole is inspected, the contractor marks each with a special tag noting the inspection year and, if performed, the types of treatment applied.

The contractor uses guidelines specified in the company's procedures for determining the quality and structural stability of the pole in keeping with the American National Standards Institute and National Electrical Safety Code standards. The poles are excavated and drilled to test for wood decay and strength. The contractors strike or "sound" the wood poles for audible signs of interior wood decay and excavate around the base of the pole to determine whether wood decay is present. The contractors also bore the poles to assess the shell thickness of the poles that have become hollow through decay.

A wood pole can be classified into several different "life-stages." A pole can be classified as normal condition, needing treatment, needing bracing, or needing replacing. The contractor keeps track of the condition of each pole inspection and, if needed, applies internal or external fumigant to treat for wood decay. The contractor can also brace the pole to increase structural support. If the pole is in either "poor" or "priority" condition, the contractor notifies the company of the need for replacement. Progress Energy states the risk of not conducting pole inspections could, under certain conditions, increase the likelihood of reliability issues.

Distribution

The company has not maintained its distribution ground-line excavation inspection 10-year cycle as outlined it its procedures. Company management states that the 10-year cycle is a baseline. Also, the company has not maintained a centralized database that monitors the overall ground-line inspection cycle. The regional managers are responsible for determining which poles are to be inspected annually and also ensuring the inspections are conducted timely in their own area. The inspection records are kept within each of the distribution regions. The company is in the process of documenting the location and condition of its distribution poles through a Global Positioning System. This is intended to allow company management to evaluate and monitor the overall inspection progress from a centralized database. This new database will

allow the company to record the location of each pole, the inspection dates, and the overall pole condition. The mapping system will not be fully implemented for eight to ten years.

The distribution group has conducted several variations of ground-line inspections during the review period. The company conducted a ground-line excavation and treatment program from 1999 through 2003. This program included a 360 degree, 18 inch-deep ground excavation of the poles. Along with the excavation program, contractors also conducted facility inspections on the company's distribution poles during 2001 through 2003. These inspections consist of monitoring the overall quality of the equipment, line, and poles.

In 2004, the company changed its inspection process to combine the facility and ground-line excavation process. The company's new approach is to target its distribution poles with a partial-excavation process. The contractor performs a visual facility inspection along with targeted ground-line excavation and testing of the pole. The later includes sounding poles, then boring those found to be hollow and checking the extent of the damage. This process thoroughly evaluates the pole's condition while removing less soil from around each pole. The same treatment and bracing criteria are still in place for these inspections. **Table 5** lists the ground-line inspections completed by the company during 1999 through 2004.

Progress Energy Distribution Pole Inspections Completed by Contractors				
Year	**Number of Planned Pole Inspections**	**Number of Ground-line Excavation Pole Inspections**	**Number of Facility Inspections**	**Number of Partial Excavation Pole Inspections**
1999	*	47,169	**	—
2000	*	45,963	**	—
2001	47,948	36,295	18,855	—
2002	44,939	45,619	68,962	—
2003	72,178	10,716	145,624	—
2004	36,364	***	***	53,049

* *1999 and 2000 planning data was not available*
** *Facility inspections were not conducted by contractors prior to 2001.*
*** *In 2004, the company combined its ground-line excavation and facility inspections into a Partial Excavation inspection process.*

Table 5

The contractors employ quality control managers who verify the work is being performed correctly. Progress Energy regional management monitors the contractors' performance by auditing the weekly and monthly status reports provided to the company by the contractors. Progress Energy does not conduct on-site reviews of the contractors' work. The contracts are three years in length and the contractors are evaluated by Progress annually.

Transmission

The transmission unit has not conducted any ground-line inspections of its wood poles during 1999 through 2004. Rather, the company states that it has focused its efforts on completing the ground patrol maintenance inspections of its approximately 49,000 transmission poles. The company states there was a backlog of ground patrol inspections needing to be

completed on its transmission facilities, and company management believed the best allocation of resources was to focus on completing all ground patrol inspections instead of having contractors complete ground-line inspections. This is discussed further in section 4.1.2.

In the aftermath of the 2004 hurricane season, the company hired a contractor to conduct assessments of each of its transmission poles in two of its four regions. These inspections examined the overall condition of each pole and the transmission equipment similar to the ground patrol inspections. The contractor identified and repaired problem poles during this process.

4.1.2 Ground Patrol Pole Inspections

Ground patrol facility inspections are conducted by the company linemen and monitor the condition of the pole and all attached equipment. These inspections include "sounding" of the wood poles to test for hollow cavities caused by decay or insects. If the poles are concrete or steel, the linemen visually assess the condition of the pole. The linemen also inspect the equipment along the line such as transformers and arresters.

The ground patrol facility maintenance inspections are conducted on a five-year cycle for both the transmission and distribution facilities. Each region conducts the patrol inspections as part of the company preventative maintenance work. If a problem is found, the lineman will conduct minor repairs on-site. If a more extensive repair is necessary, the lineman will report the condition for follow-up.

The distribution and transmission regional managers oversee the ground patrol maintenance inspections. Each manager is responsible for maintaining the schedule in the region and ensuring all maintenance repairs are conducted timely. The maintenance records are maintained within each regional area.

The transmission division has increased its focus on ground patrol inspections during the review period. In 2001, the company conducted a system-wide detailed evaluation of its transmission facilities. The company documented approximately 5,000 maintenance needs on its transmission lines. Because of these findings, the company experienced a backlog of maintenance inspections and repair needs on its transmission facilities. The company reallocated resources from the ground-line inspection process to reduce the backlog of ground patrol work.

4.2 Budgets and Expenditures

The ground-line distribution inspection expenditures were $390,992 in 2001; $549,621 in 2002; $429,029 in 2003; and $351,132 in 2004. In 2001 through 2003, along with the ground-line inspections, the contractors conducted additional facility inspections for Progress Energy. The facility budgets were $86,094 in 2001; $723,353 in 2002; and $609,379 in 2003. The 1999 and 2000 expenditures were not available.

The 1999 through 2002 inspection expenditures for transmission were $1,658,837; $2,388,594; and $2,550,891, respectively. The transmission expenditures in 2002 through 2004 were $1,116,339; $1,331,426; and $1,484,834, respectively. The 2002 through 2004 amounts

include the costs for ground patrol and aerial inspections. The 1999 through 2002 amounts include additional transmission maintenance expenditures due to pre-merger recordkeeping and are not directly comparable to the 2002 through 2004 figures.

4.3 Reliability Results

The company states that it experienced only a few outages due to defective distribution poles during the review period. The number of events annually ranged from zero to seven over the period 1999 through 2004. These events consist of pole failures that were not caused by vehicles or construction equipment damaging the poles. The CAIDI for these outage events averaged 118 minutes for the review period, but the SAIDI is less than .10 minute for each year.

During the review period, the company braced and replaced approximately one percent of its distribution poles as a result of its ground-line inspections. In 2004, 16 percent of the poles inspected during ground-line inspections were treated for wood decay. Because no transmission ground-line inspections were conducted, transmission poles were not treated for wood decay or braced during the review period. The company did replace transmission poles identified during its ground patrol and aerial inspections.

5.0 Conclusions

The following conclusions are made based on staff's evaluation of Progress Energy's vegetation, lightning protection, and pole inspection programs.

5.1 Vegetation Management

Finding 1: Progress Energy Florida has experienced an increase in vegetation-caused outages during the period 1999 through 2004, while decreasing the number of miles trimmed and the number of feeders trimmed annually during the same period.

Description: The number of outages that have been attributed to vegetation has increased during the review period. The company has seen an increase in vegetation-related outages during most of the period 1999-2004. A 17 percent decrease did occur in 2004. However, between 1999 and 2004, vegetation-related outages increased 42 percent. Also from 2002 through 2004, the percent of outages attributed to Tree—Preventable have increased in relation to the overall number of vegetation outages

Progress Energy Vegetation Outages per Year 1999-2004						
Year	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Tree—preventable	2,552	3,075	3,381	4,017	5,384	4,546
Tree—non-preventable	2,224	2,851	2,551	2,996	2,757	2,247
Total Vegetation Outages	**4,776**	**5,926**	**5,932**	**7,013**	**8,141**	**6,793**
Percent change over previous year	**-**	**24%**	**0%**	**18%**	**16%**	**(17%)**

During the same period, the number of distribution miles trimmed and the number of feeders trimmed has decreased annually. Progress Energy management states that the company is on a targeted three-year trim cycle. When looking at the rolling three-year cycle from 1999 through 2004, the company has continually trimmed fewer numbers of miles and feeders than the preceding years.

Progress Energy Three-Year Trimming Totals		
Rolling three-year cycle	**# of Miles Trimmed**	**# of Feeders Trimmed**
1999-2001	16,944	1,015
2000-2002	16,287	996
2001-2003	14,028	706
2002-2004	12,879	682

Impact: An increasing trend in vegetation-related outages can negatively impact a company's service reliability. Increased outages will likely cause more customers to be adversely effected by an electrical interruption. As much as 20 percent of the company's

Customer Minutes of Interruption (CMI) annually were attributed to vegetation-related outages, and vegetation was the leading cause of outages for the company in 2000 through 2004.

Company Response: The preliminary audit finding focuses on the number of miles and number of feeders trimmed. This is only one measure, and in this case not the best measure, of the effectiveness PEF's distribution reliability activities. Over the period from 1999 to 2004, PEF has significantly improved overall distribution reliability. The Company reduced its 1999 SAIDI of 97 minutes by over 20% and has also reduced other system reliability metrics, including SAIFI, CAIDI, and CEMI5. The breadth and magnitude of this improvement is highlighted in the Commission's most recent "Review of Florida's Investor-Owned Electric Utilities' Distribution Reliability" report. This most recent review of reliability covers the four-year period from 2000 through 2003 and shows that PEF demonstrated improvement on seven of eight reliability metrics examined.

Two factors have been key to the distribution reliability improvements achieved by PEF over this period. The first is the Company's investment of more than $120 million, over and above normal expenditures, to upgrade its transmission and distribution systems despite the reduction in revenues associated with the current rate settlement, which provided the additional benefit to customers of over $500 million in savings. The second factor is the efficiency gained from work prioritization, which allowed the Company to readjust and concentrate its reliability efforts on activities with the potential to produce the greatest improvements. The prime example of this was the emphasis placed outage mitigation, which proved to be highly effective in reducing the average duration of outages and in reducing the number of customer affected by those outages that do occur. One effect of this increased focus on outage mitigation was a somewhat reduced emphasis on outage prevention activities and the resulting increase in vegetation-related outages, although this increase was more than offset by the overall reliability improvements achieved by PEF's outage mitigation efforts. The success of these efforts can be clearly seen in the Company's decreasing CAIDI related to tree-caused outages from 2000-2004, as well as in the broad record of overall reliability improvements described above. In addition, the apparent increase in the number of vegetation-related outages has been exaggerated by recent improvements in the accuracy of cause codes assigned to outages. It is likely that many outages now reported as caused by vegetation would have been assigned other codes in the past.

Despite the emphasis on outage mitigation throughout the period in question, the Company has endeavored to maintain an average trimming cycle of three years. Vegetation management spending has risen considerably over the 1999 - 2004 period. In fact, PEF's spending of $15.4 million in 2004 is an increase of over 150 percent compared to the $9.9 million spent in 1999, and the Company's average annual spending over the three-year period from 2002 to 2004 of $14.4 million is almost 150 percent greater than the 1999 - 2001 annual average of $9.7M. However, the cost per mile for vegetation management has risen considerably over this period, which has negatively impacted the annual mileage cited in the preliminary audit finding. This increase in the cost per mile is primarily due to higher labor costs and a more comprehensive trimming program, with additional attention given to right-of-way floor maintenance and overhang removal relative to the past. Beyond this, the end of a multi-year drought has resulted in increased vegetation growth, which has contributed significantly to the rising cost per mile. In the face of these challenges, PEF has worked to more precisely target

expenditures on those activities that will achieve the maximum improvement in customer reliability. Although the Company continues to believe that a three-year weighted average maintenance cycle is a reasonable goal on a system-wide basis, there are nonetheless benefits that can be captured from the fact that preventative maintenance on certain individual feeders may be deferred to longer cycles without significantly impacting reliability. System reliability and customer impact are the ultimate drivers, and the results of this focus can be seen in the steadily declining CAIDI related to tree caused outages from 2000-2004 and the Company's broad record of reliability improvement over this period.

Going forward, PEF believes that the most significant improvements in customer satisfaction can be realized by maintaining the Company's SAIDI reliability measure in its current range and broadening the current focus on the mitigation of outages to the improvement of power quality through fault prevention. In order to both preserve the Company's reliability gains and implement this broadened focus, PEF has proposed twelve specific incremental distribution reliability initiatives as part of its rate case filing that will accelerate or go beyond existing levels of activity. These initiatives are described in the direct testimony of David McDonald. If accepted and implemented, the initiates will enable the Company to address these underlying fault prevention and cycle-time issues, while at the same time continuing its record of improving overall reliability performance.

5.2 Lightning Protection

Based on staff's review of Progress Energy's lightning protection initiatives, no issues were identified.

5.3 Pole Inspections

Finding 2: Progress Energy Florida does not currently have a fully-implemented central monitoring system to track distribution ground-line inspections.

Description: Progress Energy has not maintained a centralized database to monitor the distribution wood pole inspection process. The wood pole ground-line inspections, as outlined in the internal procedures *Preventive Maintenance of Distribution Lines* (MNT-EDGC-0002), are conducted by a contracted company that operates under the guidance of each distribution regional management. Progress Energy could not provide the inspection data for the previous 10-year cycle for distribution poles. Without this information at hand, the company cannot ensure the entire distribution system has been inspected within the cycle guidelines.

Presently, regional management oversees the contractors' work in their area and schedules the work that needs to be performed. While this structure allows the employees with the greatest working knowledge of each area the ability to prioritize the inspection process, it can also create a backlog of inspections if the work is not performed in a timely manner and if complete records are not maintained. Also, over the 10-year period, regional employee turnover could allow inspections to lag outside the cycle period or be overlooked completely.

The company has begun implementing a GPS system database to maintain pole data. This will allow the company to maintain certain inspection data. This system will allow the company to monitor the inspection process; however, the system will not be fully implemented for eight to 10 years.

Impact: Without a statewide database of the wood pole inspection results, the company can not ensure that its entire system has been inspected within the guidelines established by management. If an area is allowed to lag behind in these wood quality inspections, a pole could be compromised and customer reliability could be impacted.

Company Response: PEF enhanced its inspection program in 2003 with the implementation of a GPS tracking system, which will significantly improve the Company's ability to monitor and administer the program. Since then, the GPS coordinates of all inspected poles have been entered into the system as they are inspected. When fully implemented, approximately an additional 8 to 10 years given our inspection cycle time, PEF will be able to identify the precise location and specific inspection history for each of its approximately one million distribution poles. This data base, in turn, will enable the Company to better identify patterns and trends associated with inspection and maintenance practices and provide the basis for evaluating further improvements to its procedures, including the most cost-effective inspection cycle.

PEF believes that its current approach and timeline most appropriately balance costs and benefits for our customers since we essentially incur no incremental cost to build the database during our routine inspections. The alternative, obtaining the GPS coordinates of our poles outside the normal inspection process, would add roughly $5 million in cost and would not likely produce substantial benefits. Our experience and working knowledge of the system indicate that pole failures are very rare. The hurricanes of 2004 provide additional validation, given that only a miniscule number of our wood poles failed due to a structural defect under even the most severe conditions.

Finding 3: Progress Energy Florida has not maintained its five-year transmission ground patrol inspection cycle. This was causing a backlog of ground patrol inspections for the company and a reallocation of resources from the ground-line inspection program to reduce the backlog.

Description: Progress Energy internal procedure *Ground Patrol,* MNT-TRMX-00053, outlines the company's policies for inspecting the transmission lines and facilities. The procedure states that these inspections are crucial to identify and correct deficiencies and to allow the company to efficiently prioritize future needs. These inspections are visual inspections conducted from the ground with the linemen climbing pre-selected poles. The company's target is to inspect its transmission system every 60 months.

Progress Energy internal procedures *Transmission Line/Substation Wood Pole Inspection and Groundline Treatment,* MNT-TRMX-00057 outlines the company's policies for inspecting the quality of its wood poles and, if necessary, treating its wood poles to reduce future decay.

The company's procedures target a 10-year inspection cycle for its transmission wood poles. However, the company has not completed any ground-line inspections during the review period.

In the past, division management has not had an effective means to ensure that the ground patrol inspections occur within the 60-month cycle period. Each region's management is charged with maintaining the inspection cycle and making sure the inspections are conducted in a timely manner. Progress Energy management states there has been a backlog of the number of ground patrol inspections needing to be conducted in recent years. The ground patrol inspections are viewed by management as more critical, so the company has reallocated resources from ground-line inspections to increase its efforts on reducing the backlog.

Impact: Without routine ground patrol inspections, the company cannot be assured that its transmission facilities meet quality guidelines. Extending the inspections outside the cycle period could result in sub par facilities; leading to reduced reliability. The reallocation of resources to alleviate the backlog of these ground patrol inspections delays completion of the company's ground-line inspections as required by its procedures.

Company Response: Since 2001, the Company has dedicated four transmission line crews to inspecting and maintaining PEF's transmission lines. These crews are locally based and have direct knowledge of the facilities within their maintenance area. These crews inspect and repair lines on a routine basis. In addition, they conduct aerial patrols three times per year to further inspect the transmission facilities. These efforts are conducted with the objective to provide safe and reliable service to PEF's customers and in accordance with the PEF policy MNT-TRMX-0000 (previously provided as Attachment 3 to the Company's Response No. 2).

In recognition of the number of wood transmission poles in the queue for integrity inspections, PEF elected to prioritize its inspection efforts and resources to focus on this more critical task, with a resumption of regular preventative maintenance treatment when the backlog of integrity inspections/repairs has been significantly reduced or eliminated. This kind of priority adjustment is consistent with the Company's inspection guidelines, which recognize the need for flexibility in scheduling inspections to account for system or resource constraints as they occur from time to time. It has also reduced the Retail SAIDI due to pole failures from 0.22 in 2002 to 0.001 in 2004.

In conjunction with the increased inspections, the Transmission organization is implementing an asset management organization and philosophy wherein asset management records, activities, results and future activities are more efficiently coordinated. The transmission asset management effort is ongoing and being integrated with the maintenance organization. As discussed, PEF is in the process of adding work planners and schedulers in the transmission maintenance areas to develop work plans in support of the Company's inspection objectives.

Therefore, with respect to staff's Finding Statement 3 in general and its Impact statement in particular, PEF's reprioritization of its wood transmission pole inspections by reallocating resources from ground-line inspections to increase its efforts on reducing the backlog of corrective maintenance has not compromised the structural integrity, reliability or safety of its

transmission poles but, in fact, has focused the Company's inspection efforts on ensuring precisely those critical characteristics.