BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Progress Energy Florida

Docket No. 090079-EI

Submitted for filing: March 20, 2009

DIRECT TESTIMONY

OF

DALE OLIVER

On behalf of Progress Energy Florida

Petition for increase in rates by Progress Energy Florida

DOCKET NO.090079-EI

DIRECT TESTIMONY OF

DALE OLIVER

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Dale Oliver. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") as its Vice President, Transmission Operations & Planning Department ("TOPD", "Transmission" or the "Department"). In this role, I have overall responsibility for PEF's transmission system, including its design, construction, operation and maintenance, in order to provide reliable transmission service to PEF's retail and wholesale customers. I am also responsible for the integration of PEF's transmission system with the Florida transmission grid.

Q. Please describe your educational background and professional experience.

A. I received a bachelor's degree in electrical engineering from Georgia Tech in 1981 and an MBA from Georgia State University in 2001. Prior to assuming my current role in February, 2007, I was the Regional Vice President for PEF's South Coastal Region from October, 2005 to February, 2007, and from May 2004 to

October, 2005 the Company's Regional Vice President for the South Central Region. From 2001 to 2004, I was PEF's Director of Transmission Engineering and the Director of the Company's Commitment to Excellence ("CTE") program. Prior to joining PEF in January 2001, I held a number of supervisory and management positions in the transmission maintenance and operations areas for the Southern Company's Georgia Power subsidiary in Atlanta, Georgia. I am a registered professional engineer in the states of Florida and Georgia.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the reasonableness of PEF's transmission capital and O&M expenses.

Q. **Are you sponsoring any Minimum Filing Requirements Schedules?**

A. Yes. The Minimum Filing Requirements (MFRs) Schedules that I sponsor or co-sponsor are listed in Exhibit No. ___ (JDO-1) to my testimony. These MFR Schedules are true and correct, subject to being updated during the course of this proceeding.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. __ (JDO-1), a summary of sponsored or co-sponsored schedules of the Company's Minimum Filing Requirements (MFRs); and

- Exhibit No. __ (JDO-2), a summary of Transmission capital projects, with total capital project cost, (1) to comply with federal reliability standards, (2) to comply with regional reliability initiatives, (3) to accommodate new generation and reliability needs from expansion, and (4) to maintain the system.

These exhibits are true and correct.

Q. Please summarize your testimony.

A. PEF requires transmission capital expenditures of $185.2 million and O&M expenses of approximately $45.3 million in 2010. These expenditures enable the Company to strike a reasonable balance between the high quality of service that our regulators and our customers expect and a reasonable cost for transmission service. PEF's O&M expenses are further reasonable and necessary because they are $ 0.03 million or 0.0% above the Commission O&M benchmark cost of $38.4 million.

PEF has successfully provided reliable transmission service to its customers at a reasonable cost for years. PEF's reliability performance is consistent and at levels that drive customer satisfaction with our service. PEF's transmission reliability and operations has consistently ranked high among forty utilities across the country. PEF needs its requested transmission capital and O&M expenditures to meet the expanded capacity demands placed on the system, increasingly stringent federal reliability standards, and the Commission's storm hardening initiatives, while maintaining the reliable system operation that our customers expect. PEF has demonstrated an ability to successfully operate the Transmission side of its business by balancing the need to maintain excellence in reliability with providing transmission service at a reasonable cost.

II. PEF'S TRANSMISSION SYSTEM.

Q. Please generally describe PEF's transmission system.

A. PEF is part of a nationwide interconnected and Florida intraconnected power network that enables interconnected utilities to exchange power. As a result, PEF's transmission system is subject to regulation with respect to the reliability of its system by both the Federal Energy Regulatory Commission ("FERC") and the Florida Public Service Commission ("PSC" or the "Commission"). PEF's transmission system includes approximately 5,000 circuit miles of transmission lines, including 500 kV, 230kV, 115 kV, and 69 kV lines, transmission substations, towers, poles, and related equipment and material across 20,000 square miles in west central Florida and the densely populated areas around Orlando, St. Petersburg, and Clearwater. Within Florida, PEF's system is interconnected with the other investor-owned utilities, twenty-two municipal electric utilities, and nine rural electric cooperatives. By improving, maintaining, and adding to this transmission system when necessary, PEF reliably delivers power from generation resources to be distributed to its customers' homes and businesses around-the-clock, each day.

Q. What has the Company done to maintain and improve transmission system reliability since 2005?

A. Our base line for transmission system reliability was our 2002-2004 CTE program. The CTE program included a number of capital and O&M initiatives that improved the reliable delivery of power to our customers. From this base line, in each of the past four years we have assessed our system performance in the previous year and established priorities for the next year. For example, our annual, targeted maintenance capital expenditure plan prioritizes the replacement of transmission capital units according to the age, condition, and significance of the replacement of that unit to the overall reliability of the system. This maintenance capital expenditure plan focuses on transmission poles, pole insulators, static wire, transmission line conductor, substation transformers, breakers, capacitors, relays, and battery banks.

Our transmission O&M initiatives the past four years also built upon our CTE initiatives by focusing on initiatives that offered the greatest benefit to system reliability. To illustrate, O&M initiative spending since 2005 included vegetation management, line bonding and grounding, relay calibration, and transformer inspections in addition to our routine O&M expenditures for the transmission system.

Our annual process of planning our capital, maintenance capital, and O&M expenditures has resulted in the strengthening of our transmission grid and the enhancement of the operation of our transmission system, with continued, improved reliability performance for our customers over the last four years.

Q. How does the Company measure transmission reliability performance?

A. PEF regularly analyzes reliability data to assess and track the performance of its transmission system using generally accepted reliability measures or indices in the electric utility industry. These indices include (1) the Circuit System Average Interruption Duration Index or "Circuit SAIDI", which tracks the average duration of a transmission-related outage; (2) the System Average Interruption Frequency Index ("SAIFI"), which tracks the average frequency of transmission-caused outages; (3) the System Average Interuption Frequency Index for Momentaries ("SAIFI-M"), which tracks the average frequency of transmission-caused outages for outages of less than a minute; and (4) the System Average Restoration Index ("SARI"), which tracks the time required to re-energize circuits following an outage. These reliability indices are regularly used by utilities and regulators to assess reliability performance by tracking changes in the results of these indices from one period of time to another, later period and comparing the direction of the change and the magnitude of the change from the earlier period to that later period of time.

Q. What are the results of these reliability performance indices for PEF's transmission system?

A. For the latest completed five-year window (2003-2007), PEF's transmission system reliability improved. All of these reliability indices that PEF regularly tracks showed positive trends. Specifically, Circuit SAIDI decreased by 23.4%, SAIFI decreased by 7.9%, SAIFI-M decreased by 10.1%, and SARI decreased by 20.6%. These positive trends demonstrate that PEF is providing customers with reliable transmission service. They further demonstrate that PEF has reasonably and prudently maintained its transmission system over time, when the transmission system has expanded and the existing transmission assets have further aged, adding to the cost to maintain and improve system reliability. Our reliability performance under increasing cost pressures indicates our commitment to excellent customer service.

Q. Are there other ways that PEF monitors its transmission performance?

A. Yes. PEF annually participates in a benchmarking study managed by an outside contractor. This benchmarking study, known as the *SGS Transmission Reliability Benchmarking Study*, includes approximately 40 other utilities from around the country comprising almost half of the transmission circuit miles in the United States. PEF has consistently compared well against the benchmark group for several years now, and particularly given the often harsh conditions under which our system operates.

Q. Has PEF maintained the reliable transmission of power to customers at a reasonable cost?

A. Yes. Since 2005, PEF has continued to incorporate best practices in the industry to manage and control its transmission-related capital and O&M costs. For example, we set up an organizational model that includes a unit in the

Transmission Maintenance Section called Maintenance Resource Management that is comprised of Resource Coordinators who are responsible for planning and scheduling all capital and O&M-related work performed in our transmission areas. This group provides efficient and organized maintenance work scheduled and monitored at 15-minute increments, where appropriate. They also procure necessary materials and closely monitor their delivery to ensure their timely and cost-effective use to maintain the system. Our results over the last three years demonstrate that the Maintenance Resource Management processes are working and contributing to overall reliability improvement at a reasonable cost.

Additionally, in 2007 we created a new Project Support group in our Project Management unit that focuses on optimizing the scheduling, procurement of materials, and management of contract support work. This Project Support group improved the organization of maintenance, planning, engineering, and construction group projects with resulting cost savings. Also in 2007, a Transmission Finance group comprised of several business financial analysts was created to more efficiently achieve our operational objectives by providing improved budgeting, cost management, and business planning support. Transmission Finance continuously works with Transmission to facilitate informed decision making, increase productivity, decrease costs, and establish effective internal controls. As a result, of these measures and others, PEF's Transmission management efficiently provides our customers with reliable transmission service.

Q. Can you provide us with some of the other ways Transmission ensures the Company is providing reliable transmission service to customers in an efficient, cost-effective manner?

A. Yes. Our improved safety record has also contributed to the delivery of reliable transmission service to customers at a reasonable cost. Transmission has demonstrated continually improving safety records since 2002. Our OSHA-recordable injury totals have improved from eleven injuries for 2002 to five injuries for 2008. The corresponding improvement in OSHA injury rates was from 3.04 in 2002 to 1.05 in 2008. These improvements were made with increases in employees and, accordingly, the hours worked. Transmission employs over 400 employees working nearly 1,000,000 hours annually, performing tasks that have inherent risk much of that time. As a result, we have an excellent safety record that demonstrates our commitment to a safety culture. Customers benefit directly from our exemplary safety record in transmission because the Company does not experience the lost time and inefficiencies that result from job-site injuries and the required investigations, "lessons learned" practices, and time and cost of dealing with potential employee and third party claims.

Additionally, our training programs benefit our customers by improving our ability to efficiently and reliably provide customers transmission services. One example is the training program for System Dispatchers at our Energy Control Center (ECC). PEF Dispatchers must be certified at the Reliability Authority level by the North American Reliability Corporation ("NERC"), which was established as a result of the Federal Energy Policy Act of 2005 ("EPAct") to develop and enforce mandatory transmission reliability standards. As a result, they are required to obtain 200 Continuing Education Hours (CEH's) over a three-year period to maintain their certification. To acquire these CEH's, the ECC Training team annually provides 80 hours of training classes that consist of presentations, discussions, simulation (including hours of one-on-one simulation training), and debriefs on operational and other issues. Additional training hours consist of computer-based and written material based on Plantview modules and PEF ECC Procedures and Policies. Overall, PEF System Dispatchers will receive 120 to 140 hours of training annually to maintain their performance skills in an ever changing transmission system. This training is also required for PEF to comply with Federal Energy Regulatory Commission ("FERC"), NERC, and Florida Reliability Coordinating Council ("FRCC") regulation.

All other Transmission personnel are required to receive training as well. This training includes OSHA Compliance, Safety, Environmental, and skill-based technical training. Our training programs continually increase our employees' ability to provide efficient, safe, and reliable transmission service to our customers.

Our new outage management software application, known as the Transmission Outage Management System (TOMS), implemented since 2005, also improves the efficient delivery of reliable transmission service to our customers. TOMS manages outages in a well-organized manner, listing the physical location of the event (i.e. nearest street address and nearest substation or transmission line structure number), tracks the number of customers affected by the particular event, and tabulates the number of calls that have been received for the event. TOMS also provides information on the location and magnitude of the short circuit associated with the outage, if there is one. This information is not only extremely helpful in a storm scenario when multiple outages are underway, but it is also useful for any outage that occurs on the transmission system. TOMS has resulted in our ability to respond to transmission outages in a very organized and thus efficient fashion, in both storm and non-storm conditions.

Q. Can the Company continue to provide customers with reliable transmission service?

A. Yes, but maintaining our record of reliable transmission service requires additional capital and O&M investment in the transmission system. One reason is that PEF's transmission system is simply larger today compared to 2005. The transmission system therefore includes additional transmission assets that must be maintained. Another reason is that PEF must continue to invest in capital additions to the transmission system to meet increased customer capacity demand on the system and to replace a continually aging infrastructure. These capital and O&M investment needs coincide with labor, material, fuel, real estate corridor, and permitting cost escalations, requiring additional funding for these investments.

There is another reason too for our additional capital and O&M investments in the transmission system. Regulatory initiatives at both the federal and state level mandate changes in the way transmission planning occurs and change the way we operate and maintain our transmission system. These regulatory initiatives further require PEF to incur additional capital and O&M expenditures to comply with the regulatory initiatives.

III. FEDERAL AND STATE REGULATORY RELIABILTY INITIATIVES.

Q. What are the federal reliability initiatives that affect Transmission planning and investment?

A. EPAct in 2005 directed the FERC to establish an Electric Reliabilty Organization ("ERO") to establish and enforce national transmission reliability standards. The FERC complied by certifying NERC as its ERO and the FERC authorized NERC to make the previously voluntary reliability standards mandatory, adopt new or more stringent mandatory reliability standards, and enforce them. The NERC adopted more stringent and new mandatory reliability standards pursuant to the FERC's authorization and direction. Noncompliance with these reliability standards subjects electric utilities to enforcement actions and penalties.

The FERC further issued various Orders directing the operation and regulation of electric utility transmission systems and requiring increased transparency in the planning of transmission systems between electric utilities and/or any interested stakeholders in the transmission system. Also, in conjunction with NERC's transmission planning and reliability activities, the FRCC has taken an increasingly active role in transmission planning and reliability from a regional perspective.

Compliance with the FERC, NERC, and FRCC orders, reliability standards, and planning coordination initiatives requires Transmission to implement new processes and augment existing planning processes. Transmission must also incur capital and O&M expenses to comply with these standards and initiatives.

Q. Can you explain how these federal regulatory directives or initiatives have influenced PEF's transmission planning?

A. Yes, I can. The most straight-forward impact results from the NERC designation as the ERO with increased control over transmission reliability. The NERC adopted and the FERC approved more stringent transmission reliability standards. An administrative process and potentially significant fines follow from noncompliance with these standards. To comply with these NERC reliability standards, PEF must plan for and invest in Transmission capital projects that, absent these standards, are not mandatory and therefore required.

Additionally, FERC Order 890 establishes Nine Principles of Transmission Planning. These principles mandate more transparency in the transmission planning process and require additional administrative processes and increased regulatory scrutiny to ensure that transparency is achieved. PEF has historically been open and helpful in the transmission planning process with PEF's customers, and with the NERC and FRCC, but the additional administration and regulatory scrutiny means additional cost to PEF in the transmission planning process for both PEF's internal transmission planning analyses and analyses performed in joint planning efforts with other utilities.

The increased federal activity in transmission planning and reliability through the FERC and the NERC has also led to additional transmission planning and reliability activity at the regional level. Within Florida, the FRCC provides technical assistance to identify the reliability need for large transmission projects. As the NERC's activity in transmission planning has increased so has the FRCC's, resulting in a several-fold increase in the FRCC reliability workload since the beginning of 2005. The increased FRCC activity resulted in increased findings of the need to construct transmission capital projects to mitigate reliability excursions from FRCC and NERC criteria. These findings translate into increased transmission costs for PEF.

Finally, the FRCC's increased activity in transmission reliability planning has led the FRCC to focus on the reliability of the PEF 69 kV system. PEF presently has over 2,000 circuit miles of 69 kV lines serving dozens of PEF and Rural Electric Cooperative substations. A significant portion of the 69 kV system provides flow-through, grid-related reliability support, and thus it functions practically the same as the Bulk Electric System ("BES"). Thus, the 69 kV system is important to the reliability of PEF's system even though it is not covered by any existing NERC standard. PEF has continually invested in the 69 kV system to maintain its reliability because of its importance to PEF's overall system and customers. With the additional emphasis that the FRCC has placed on the 69 kV system, PEF is making even further investments in that system.

Q. You also mentioned state regulatory initiatives that have impacted PEF's transmission capital and O&M requirements. Can you explain what those state regulatory initiatives are?

A. Yes. The Commission has issued two Orders and enacted Rule 25-6.0342, Florida Administrative Code (F.A.C.), to require Florida investor owned utilities ("IOUs") to harden their systems against potential storm outages and damage. In February 2006, the FPSC issued Order No. PSC-06-0144-PAA-EI, requiring all Florida IOUs to implement an eight-year wood pole inspection cycle program. Consequently, PEF now files a Wood Pole Inspection Plan every three years with an inspection report submitted annually. The annual reports contain 1) the methods PEF used to determine National Electrical Safety Code ("NESC") compliance, 2) an explanation of the inspected poles selection criteria including geographic location and the rationale for including each selection criterion, 3) summary data and results of PEF's previous wood pole inspections addressing the strength, structural integrity and loading requirements, and 4) the cause for the poles failing inspection and actions taken by PEF to correct each pole failure.

In April 2006, the Commission also issued Order No. PSC-06-0351-PAA-EI, requiring all IOUs to file plans and estimated implementation costs for ten ongoing storm preparedness initiatives identified by the Commission. PEF consequently filed its Storm Preparedness Plan on June 1, 2006. PEF's Plan implemented processes meeting the requirements of the Commission's ten storm preparedeness initiatives. In February 2007, the Commission enacted Rule 25-

6.0342, F.A.C. This rule mandates various storm hardening requirements for Florida electric utility transmission and distribution systems.

The Rule requires, at a minimum, that each IOU's storm hardening plan address the following: (1) Compliance with the NESC; (2) Extreme wind loading (EWL) standards for: (i) new construction, (ii) major planned work, including expansion, rebuild, or relocation of existing facilities, and (iii) critical infrastructure facilities and along major thoroughfares; (3) Mitigation of damage due to flooding and storm surges; (4) Placement of facilities to facilitate safe and efficient access for installation and maintenance; (5) A deployment strategy including: (i) the facilities affected, (ii) technical design specifications, construction standards, and construction methodologies, (iii) the communities and areas where the electric infrastructure improvements are to be made, (iv) the impact on joint use facilities on which third-party attachments exist, (v) an estimate of the costs and benefits to the utility of making the electric infrastructure improvements, and (vi) an estimate of the costs and benefits to third-party attachers affected by the electric infrastructure improvements; and (6) Attachment standards and procedures for third-party attachers.

On May 7, 2007, PEF filed its 2007 Electric Infrastructure Storm Hardening Plan (Docket No. 070298-EI). This Plan consolidated the requirements of the previous Orders and the new Rule into a single plan. As a result, PEF is meeting all storm hardening requirements and initiatives for its transmission system, at additional capital and O&M cost to PEF.

IV. TRANSMISSION CAPITAL AND O&M REQUIREMENTS.

Q. What are PEF's transmission capital and O&M expenditure requirements for 2010?

A. PEF requires $185.2 million in transmission capital spending and $45.3 million in O&M expenses.

Q. How much of the required transmission capital spending is required by NERC and FRCC reliability initiatives and expansion?

A. $140.3 million of the $185.2 million in transmission capital spending is allocated for planning, engineering, and construction expenditures for expansion of the PEF transmission system for NERC reliability initiatives and additional generation. The scope of PEF's transmission work required by the NERC Standards, in particular the NERC Transmission Planning (TPL) Standards, has increased significantly. PEF has successfully managed this increase in scope by recently completing several major capital projects and remaining on schedule to complete many others. Examples include the Vandolah - Hardee 230 kV line upgrade and the Lake Bryan – Windmere 230 kV circuit number 2 construction and circuit number 1 rebuild. Implementation of these projects and others assist PEF in complying with the NERC TPL standards, increase the reliability of the grid in the Central Florida area, and demonstrate our continuing commitment to our customers and stakeholders to provide reliable transmission service in compliance with regulatory reliability standards. My Exhibit No. ___ (JDO-2), has a more detailed list of PEF NERC compliance-related transmission projects in Section A of that Exhibit.

PEF is also expanding its transmission system to accommodate new generation on the system and additional transmission reliability needs. Sections B and C of my Exhibit No. ___ (JDO-2) provide detailed lists of major transmission projects relating to the generation additions and other major transmission reliability needs. Additionally, PEF is building additional new 69 kV lines or rebuilding existing ones. All new 69 kV construction is built to 115 kV specifications to provide increased reliability and performance. As I explained, PEF's additional investment in its 69 kV system in part satisfies the FRCC's interest in enhanced reliability of the 69 kV system. PEF's major 69 kV transmission capital projects are listed in Section D of Exhibit No. ___ (JDO-2).

Q. How did PEF determine that these transmission projects were required?

A. Each calendar year, transmission planning performs analyses for the long-term, ten-year transmission planning cycle, i.e. beginning one year out from present day through year ten. These analyses are performed from three distinct planning perspectives. First, the analyses by transmission planning must demonstrate that the PEF system will be in compliance for the ten-year planning period with the mandatory NERC reliability standards, specifically NER Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and FAC-010-2. If the analysis shows that the PEF system deviates from these standards PEF must initiate either an operational mitigation strategy or a new transmission capital project to bring the system back in compliance with the standards.

Second, an analysis is performed to demonstrate transmission system compliance with FRCC reliability standards. This analysis is similar to the analysis performed to ensure system compliance with the NERC reliability standards. The primary difference between the two analyses is that the FRCC treats the 69 kV system as if it is part of the BES. The lower bound under current NERC Reliability Standards is 100 kV. Third, additional analysis is performed to address the interconnection of new retail delivery points, such as new residential or commercial developments that require capital expansion of PEF's existing transmission system.

After these analyses are complete, PEF's transmission planning process requires the review of proposed transmission projects by other PEF areas affected by the proposal for feasibility and possible alternatives, if necessary. PEF's Project Review Group (PRG) subjects proposed transmission projects to multiple phases of review before a project is approved and included in the Transmission capital budget. All transmission capital projects are therefore carefully reviewed and scrutinized to ensure they are needed to provide customers with reliable transmission service at a reasonable cost.

Q. How much of the required transmission capital is for maintenance capital expenditures?

A. PEF needs $44.9 million for maintenance capital expenditures. Required maintenance capital expenditures are generally based on assessments of our system performance the previous year, with priority assigned to replace transmission capital property units according to age, condition, and significance with respect to system reliability. Additional maintenance capital work is required to comply with NERC TPL reliability activities. Further, PEF must perform maintenance capital work as part of its storm hardening plan to comply with the Commission's storm preparedness initiatives in the storm hardening orders and rule. In sum, PEF prioritizes maintenance capital expenditures to deliver the most cost-effective, reliable power that its customers already enjoy and have come to expect, consistent with federal and state regulations, initiatives, and policies.

PEF's $44.9 million maintenance capital expenditures include $16.8 million for line improvements. An additional $12.9 million is for emergency spare power transformers, $12.0 million is for substation equipment replacement and refurbishment, and $3.2 million is for needed vehicle replacements, operating system upgrades, tools and test equipment. All of these maintenance capital expenditures are required to replace aging infrastructure, strengthen the transmission grid, and enhance the operation of our system, resulting in safe and reliable service to the Company's customers.

Q. Please explain PEF's required transmission O&M expenses.

A. PEF needs $45.3 million for transmission O&M expenses. This funding is needed to perform required maintenance to maintain reliability and to satisfy federal and state regulatory requirements and policies.

For example, PEF has undertaken measures to significantly increase its tree-trimming initiatives in order to comply with NERC Standard FAC-003-1. Enhanced vegetation management is also an aspect of the Commission's storm hardening initiatives. Vegetation management within and adjacent to existing transmission corridors is a critical component of transmission maintenance, assuring the safe and reliable operation of the transmission system. It includes tree trimming, hand cutting, mowing, danger tree removal, a proactive herbicide program and aerial patrols to assess system conditions. The $45.3 million O&M costs includes a $2.1 million increase to the transmission vegetation management program as compared to benchmark spending, bringing the overall program spending up to $9.3 million for 2010.

PEF has also undertaken major initiatives to maintain relays, instrument transformers, Special Protection Systems (SPSs), Under-Voltage Load Shedding Schemes (UVLS), Under-Frequency Load Shedding Schemes (UFLS) and substation control house battery banks to comply with the NERC Protection and Control (PRC) Standards. Additional maintenance capital is required for substation maintenance, the inspection of transmission lines, dispatch load, and planning the transmission system. Also included in the $45.3 million O&M expenses are specific reliability initiatives of $2.0 million for line bonding and grounding, bushing replacements, and cap and insulator replacements. These reliability programs are incremental to base funding and assist PEF in preventing outages before they occur, enabling PEF to continue to deliver the cost-effective, reliable power to our customers that they expect.

Q. Are PEF's required 2010 Transmission capital and O&M expenses reasonable?

A. Yes, they are reasonable and necessary for PEF to continue to provide reliable transmission service to its customers in compliance with NERC and FRCC reliability standards and the Commission's storm hardening initiatives.

PEF's O&M expenses are further reasonable and necessary because they are $ 0.03 million or 0.0% above the Commission O&M benchmark cost of $38.4 million. This calculation excludes the $6.9 million PEF will incur to comply with FERC Order 890. FERC Order 890 did not exist in 2006 and therefore these costs were not and could not be included in the base costs for the Commission's O&M benchmark test. Further, because PEF must incur these costs to comply with a FERC Order, they are beyond PEF's control.

PEF's required O&M expenses will support basic operation and maintenance activities to strengthen the grid and enhance the operation of our system. These expenditures are therefore reasonable and necessary to ensure compliance with NERC and FRCC Reliability Standards, to comply with Commission storm hardening initiatives, and to provide excellent customer service.

Q. Does this conclude your testimony?

A. Yes.

MINIMUM FILING REQUIREMENT SCHEDULES
Sponsored, All or in Part, by J. Dale Oliver

Schedule	Schedule Title
B-7	Plant Balances by Account and Sub-Account
B-8	Monthly Balances Test Year – 13 Months
B-9	Depreciation Reserve Balances by Account and Sub-Account
B-10	Monthly Reserve Balances Test Year – 13 Months
B-13	Construction Work in Progress
C-6	Budgeted Versus Actual Operating Income and Expenses
C-8	Detail of Changes in Expenses
C-9	Five Year Analysis – Change in Cost
C-15	Industry Association Dues
C-33	Performance Indices
C-34	Statistical Information
C-35	Payroll & Fringe Benefit Increases Compared to CPI
C-36	Non-Fuel Operation and Maintenance Expense Compare to CPI
C-37	O&M Benchmark Comparison by Function
C-38	O&M Adjustments by Function
C-39	Benchmark Year Recoverable O&M Expenses by Function
C-41	O&M Benchmark Comparison by Function

Project Description	Completion Date	Total Project Capital Cost
Section A: Major NERC Compliance-related Transmission Capital Projects:		
Avalon – Gifford 230 kV line	May 2010	$39M
Dundee – West Lake Wales 230 kV circuit #1 rebuild and circuit #2	Nov 2009	$22M
Dundee – Intercession City 230 kV circuit #1 rebuild and circuit #2	June 2010	$41M
Avon Park to Ft Meade 115 kV line – convert to 230 kV	May 2009	$20M
Central Florida South – Install new Substation with one (1) 500/230 kV Transformer	Nov 2014	$28M
Dale Mabry to Zephyrhills North – install new 230 kV Line	Oct 2014	$67M
Hines – West Lake Wales – Install 2nd 230 kV circuit	May 2012	$20M
Northeast to Disston – Install new 230 kV line, one (1) new 230/115 kV Transformer at Disston	Oct 2011	$17M
Disston – 40th Street – Install New 230 kV Line	May 2014	$20M
Brooksville West – Install 2nd 230/115 kV Transformer	May 2011	$8M
Quincy – Havana – Rebuild existing 115 kV line to higher ampacity	May 2012	$12M
Havana – Bradfordville – Rebuild existing 115 kV line to higher ampacity	May 2013	$11M
Brooksville West – Brooksville 115 kV – Rebuild both circuits to higher ampacity	Nov 2012	$12M

Project Description	Completion Date	Total Project Capital Cost
Section B: Major Transmission Projects affiliated with the Bartow Repowering Project:		
Bartow Plant – Northeast – install three (3) new 230 kV underground cables	March 2009	$80.2M
Bartow – Substation Termination work for Cables	August 2008	$18.6M
Northeast – Substation Termination work for Cables, and replace Northeast 230/115kV 224 MVA Transformer Banks 4 and 5 with 300 MVA Banks	March 2009	$17.6M
51st Street Substation – Loop in 40th Street – Pasadena 230 kV line, add new 230/115 kV 300 MVA Transformer	June 2009	$12.3M
Northeast – 32nd Street – install one (1) new 115 kV line	March 2009	$3.8M
32nd Street – Gateway 115 kV – Install mid-span poles	October 2008	$1.0M
Northeast – 40th Street 230 kV line – Rebuilding existing line to higher ampacity	March 2009	$7.7M
Section C: Other Major 500 kV and 115 kV Transmission Projects:		
West Leon – Install New 115/69 kV Substation	May 2012	$15M
Hancock Road – Install new 230/69 kV Substation	May 2012	$18M
Bushnell East – Install new Substation with one (1) 230/69 kV Transformer	May 2012	$20M
Bithlo – Install 230/69 kV Transformer and loop in FPL 230 kV line	April 2010	$26M
Section D: Major 69 kV Transmission Capital projects:		
Port St. Joe to Apalachicola – Install New 69 kV	June 2011	$21M
Apalachicola – Eastpoint – Rebuild existing 69 kV	May 2015	$20M

Project Description	Completion Date	Total Project Capital Cost
circuit to Double-Circuit		
Perry – Smith Tap – Luraville – Rebuild existing 69 kV circuits to higher ampacity	Feb 2011	$11M
Fort White – Luraville – O'Brien – Rebuild existing 69 kV circuits to higher ampacity	June 2013	$18M
Carrabelle – Eastpoint – Rebuild existing 69 kV circuit to higher ampacity	May 2014	$16.5M
Chiefland – Install New 69 kV Switching Sub and loop in 69 kV lines	May 2013	$9M
Turnpike – Install New 230/69 kV Substation and new Turnpike – Okahumpka 69 kV Line	May 2014	$15M
Holder – Install 2nd 230/69 kV Transformer and 2nd Holder – Dunnellon 69 kV line	Nov 2010	$20M
Hull Road – GE Alachua – Rebuild existing 69 kV circuit to higher ampacity	Oct 2012	$25M