BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060007-EI

ENVIRONMENTAL COST RECOVERY CLAUSE

March 31, 2006

DIRECT TESTIMONY & EXHIBITS OF:

JOHN HOLLER

Progress Energy

PROGRESS ENERGY FLORIDA

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Environmental Cost Recovery Clause

DIRECT TESTIMONY OF
JOHN HOLLER

March 31, 2006

Q. Please state your name and business address.

A. My name is John Holler. My business address is 15760 West Power Line Street, Crystal River, Florida 34428.

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

A. I am employed by Progress Energy Florida, Inc. (PEF) as a Principal Engineer in the Plant Construction Department.

Q. What are your responsibilities in that position?

A. I am responsible for the engineering, budget development, and completion of major environmental control projects at PEF's four-unit coal-fired Crystal River plant, and PEF's five oil-fired units at the Anclote and Bartow Plants. Among other things, our department helps develop and initiate air compliance strategies for PEF's fleet of fossil units in response to regulatory and company initiatives.

Q. Please describe your educational background and professional experience.

A. I received a Bachelors of Science Degree in Mechanical Engineering from Cornell University. I have thirty years of experience in all phases of the power generation business including operations, maintenance, fuels, environmental compliance, capital additions, new plant development and acquisitions. I have been involved in financial and technical aspects of managing, evaluating and developing power generation assets, including air pollution control projects. During my thirty year career in the power industry, I have been involved in the assessment, design, and installation of numerous air emission control projects, including controls on nitrogen oxide (NOx) emissions, such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) systems, Low NOx burners (LNB) and over-fire air (OFA) systems, as well as Flue Gas Desulphurization systems (FGD or "scrubbers") for control of sulfur dioxide (SO_2) emissions.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit No. __ (JH-1) which provides a conceptual level schematic of the primary emission control technologies for utility boilers, such as those operated by PEF.

Q. What is the purpose of your testimony?

A. In Order No. PSC-05-0998-PAA-EI, the Commission found that costs for complying with the new Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) are eligible for recovery through the ECRC subject to PEF's demonstration that costs for specific projects are reasonable and prudent as they are submitted for recovery in the annual ECRC proceedings. Since that time, PEF has conducted extensive analysis to develop an Integrated Clean Air Compliance Plan, which is presented in a report provided as Exhibit No. __ (DJR-1) to Mr. Roeder's pre-filed direct testimony. The primary purpose of my testimony is to explain how PEF's Integrated Clean Air Compliance Plan will meet the requirements of the CAIR, CAMR, and the new Clean Air Visibility Rule (CAVR). Among other things, I will provide an overview of the new regulations, describe various emission control technologies that PEF has analyzed, and discuss uncertainties associated with implementation of PEF's compliance plan.

Q. Please describe your role in the development of PEF's Integrated Clean Air Compliance Plan.

A. Initially, I worked with the Company's environmental professionals in evaluating the requirements of CAIR, CAMR, and CAVR to estimate the amount of emission reductions that PEF would need to achieve in order to comply with the new regulations. I analyzed the technical feasibility of various emission reduction measures for those units. I also developed emission reduction and cost estimates for various control technologies that were used in developing and analyzing alternative compliance plans. The primary emission controls for utility boilers are discussed below and shown at a conceptual level in the schematic attached as Exhibit No. __ (JH-1) to my testimony.

Q. You mentioned that you reviewed and evaluated the requirements of the new regulations. Please briefly describe the Clean Air Interstate Rule (CAIR).

A. CAIR was signed by the Acting Administrator of the U.S. Environmental Protection Agency (EPA) on March 10, 2005. CAIR requires significant reductions of SO_2 and NOx emissions from power plants in 28 eastern states and the District of Columbia through an emissions cap-and-trade program or other means. When fully implemented, CAIR is expected to reduce SO_2 emissions in these states by over 70 percent and NOx emissions by approximately 65 percent as compared to current levels. CAIR will be implemented by the affected states through revised State Implementation Plans (SIPs) designed to ensure that state-specific emission budgets are achieved by the required deadlines. Affected states are required to submit their SIP revisions to EPA for approval no later than September, 2006.

Q. What are the sulfur dioxide (SO_2) requirements of CAIR?

A. CAIR requires significant reductions in SO_2 emissions in the affected 28-state region. The reductions will be implemented in two phases – the first phase beginning in 2010 and the second phase beginning in 2015. CAIR encourages states to use the cap-and-trade approach that was established in Title IV of the 1990 Clean Air Act Amendments, which is also known as the acid rain program. Under Title IV, SO_2 emissions allowances were allocated to all affected units. CAIR implements the additional reductions by increasing the number of allowances required to offset SO_2 emissions. Beginning in 2010, CAIR requires two allowances for each ton of SO_2 emitted, as compared to the one allowance per ton requirement under the existing Title IV program. Beginning in 2015, each ton of emissions will require 2.86 allowances. Based on these changes, PEF estimates that the Company would need to reduce its SO_2 emissions between 66,000 and 84,000 tons per year, but generally around 72,000 tons per year, in order to comply with CAIR without purchasing SO_2 allowances.

Q. What are the nitrogen oxides (NOx) requirements under CAIR?

A. CAIR also requires significant reductions in NOx emissions in the affected 28-state region. As with SO_2, the NOx emission reductions also will be implemented in two phases – the first phase beginning in 2009 and the second in 2015. CAIR encourages use of a cap-and-trade approach to achieve the required emissions reductions. Under EPA's model cap-and-trade program, EPA will allocate emission allowances to each participating state. For instance, Florida would be allocated 99,445 allowances from 2009-2014 and 82,871 allowances in 2015 and thereafter. Participating states will then allocate their budgeted allowances to individual emitting units. Allocations will be made separately for both the annual and "ozone season" (May through September) periods. Assuming Florida implements a NOx cap-and-trade program, PEF estimates that its NOx emissions would have to be reduced by approximately 21,000 to 28,000 tons per year and by approximately 11,000 to 14,000 tons during the ozone season (May-September) to comply with CAIR without purchasing NOx allowances.

Q. Please briefly describe the Clean Air Mercury Rule or "CAMR."

A. The final CAMR was signed by the Acting EPA administrator on March 15, 2005. CAMR will be implemented in two phases: the first phase beginning in 2010 and the second in 2018. When fully implemented in 2018, CAMR will result in a 70 percent reduction in mercury emissions from coal-fired power plants nationwide. Like CAIR, CAMR encourages states to implement a cap-and-trade program to achieve the required emissions reductions. Under the CAMR cap-and-trade program, EPA will allocate mercury emissions allowances to each state, which will then allocate them to individual coal-fired units. In its initial plan for CAMR adoption, the Florida Department of Environmental Protection (DEP) proposed to implement unit-specific emission limits and compliance schedules rather than the federal cap-and-trade approach. If the final DEP rule imposes unit-specific emission limits rather than a cap-and-trade approach, PEF would not have the flexibility to meet its emission allocations by controlling some units but not others or by purchasing allowances. CAMR also requires that Continuous Mercury Monitoring Systems be installed on all coal-fired units by January 1, 2009, one year prior to implementation of the Phase I emission caps.

Q. Please briefly describe the Clean Air Visibility Rule or "CAVR."

A. On June 15, 2005, EPA finalized amendments to the 1999 regional haze rule now known as the Clean Air Visibility Rule (CAVR). Among other things, the final version of CAVR requires best available retrofit technology (BART) controls for certain industrial facilities emitting air pollutants that reduce visibility in certain "Class I" areas, including national parks and wilderness areas. There are four such areas in Florida, including Everglades National Park, Chassahowitzka National Wildlife Refuge and the St. Marks and Bradwell Bay Wilderness Areas.

BART requirements apply to facilities that began operation between August 1962 and August 1977. These include four PEF units: Anclote Unit 1, Bartow Unit 3, and Crystal River Units 1 and 2. However, the final CAVR provides that participation in the CAIR cap-and-trade program may substitute for BART requirements. Thus, if DEP adopts the CAIR cap-and-trade programs, PEF may not be required to install BART on the units subject to CAVR. Even in states adopting CAIR, however, controls may be required for individual units that are shown through modeling to contribute significantly to visibility impairment in a Class I area.

Q. What is the current status of DEP's implementation of the new federal rules in Florida?

A. As noted above, CAIR requires affected states to submit SIP revisions to EPA for approval by September 2006. DEP has begun the SIP revision process and intends to meet the September 2006 deadline. In initial rule development workshops, DEP indicated that it intends to adopt SO_2 and NOx cap-and-trade programs to implement CAIR requirements. However, the details will not be known until DEP finalizes its SIP revision. If DEP does not meet the September 2006 SIP deadline, the federal SO_2 and NOx cap-and-trade programs would automatically take effect under a Federal Implementation Plan (FIP) promulgated by EPA on March 15, 2006.

Much like CAIR, CAMR and CAVR requires states to submit SIP revisions to EPA for approval by November 17, 2006 and December 17, 2007, respectively. DEP has begun the SIP revision process for both rules and plans to comply with the applicable deadlines.

Q. Can the company wait until DEP's SIP revisions are finalized before it begins to implement its compliance plan?

A. No. As discussed below and detailed in the report provided as Exhibit No. __ (DJR-1) to Mr. Roeder's testimony ("Clean Air Report'), PEF's compliance plan includes the installation of emission controls, such as SCR and LNB/OFA systems for NOx and FGD systems for SO_2. Based on the Company's experience, SCR projects generally require approximately 30-36 months to complete, while FGD projects generally require approximately 42-48 months and LNB/OFA projects generally require 18-24 months. Although some uncertainty remains as to how the federal rules will be implemented in Florida, given the long lead times for installing these pollution control systems, PEF must begin implementing its compliance plan if the Company is to meet the CAIR compliance deadlines (i.e., 2009 for NOx and 2010 for SO_2). Moreover, there is little, if any, reason to believe that PEF will be allocated more emission allowances under the final DEP SIP revisions than under the EPA cap-and-trade programs.

Q. You previously mentioned that you reviewed emissions information for PEF's generating units to identify which units could be controlled to achieve the likely amount of required emission reductions. Which units did you identify?

A. As discussed in more detail in Chapter 2 of the Clean Air Report, with the repowering of PEF's Bartow Units, the Crystal River and Anclote units will contribute over 80 percent of PEF's projected SO_2 and NOx emissions total, and the Crystal River units contribute all of PEF's projected mercury emissions under CAMR. For these reasons, our analyses focused primarily on the technologies available for the Crystal River and Anclote units.

Q. Please describe the Crystal River and Anclote Units.

A. Crystal River Units 1 and 2 are similar coal-fired units, with Unit 1 nominally rated at 400 MW and Unit 2 nominally rated at 500 MW. These units currently burn coal with approximately 1.8 lbs/mmBtu of sulfur content to meet at permitted SO_2 emissions limit of 2.1 lbs/mmBtu. Both units have had Low-NOx Burners (LNBs) and Overfire Air (OFA) systems installed to meet annual permitted NOx emissions limits of 0.4 lbs/mmBtu.

Crystal River Units 4 and 5 are virtually identical coal-fired units that are nominally rated at 740 MW each. These units currently burn "compliance" coal with a sulfur content of 1.2 lbs/mmBtu to meet permitted SO_2 emissions limits of 1.2 lbs/mmBtu. Both units have the original coal burners that were guaranteed for a maximum NOx emissions level of 0.7 lbs/mmBtu. Tuning of the coal and air flows through the burners has allowed the units to comply with their current annual permitted NOx limit of 0.5 lbs/mmBtu.

Anclote Units 1 and 2 are nearly identical units that are nominally rated at 500 MW each. The units are permitted to burn residual fuel oil with an annual average SO_2 content of 1.5 lbs/mmBtu. The units also have the capability of burning natural gas (when available) up to 40 percent of the total heat input to the boilers. No NOx controls have been retrofitted to these boilers and the units are currently not subject to permit limits for NOx emissions. The units currently operate with NOx emissions averaging approximately 0.34 lbs/mmBtu.

Q. You previously mentioned that you analyzed and developed cost estimates for various emission controls. What SO_2 emission controls did you evaluate?

A. As detailed in Chapter 4 of the Clean Air Report, for SO_2, we evaluated the use of wet and dry FGD or "scrubber" systems. In addition to these emission control systems, as discussed in Mr. Roeder's testimony and Chapters 10 and 11 of the Clean Air Report, the Company also analyzed fuel switches as a potential means of reducing SO_2 emissions.

Q. Please explain the difference between "wet" and "dry" FGD systems.

A. Both types of FGD systems are also known as "scrubbers", as they "scrub" SO_2 from the flue gas of the boiler. In a dry FGD system, flue gas from the boiler is ducted into a large "Spray Dry Absorber Vessel" that is normally installed at the outlet of the boiler, prior to the boiler's particulate control equipment. As the boiler flue gas passes through this vessel, a slurry of lime and water is sprayed into the gas, causing a chemical reaction between the SO_2 in the gas and the lime and the alkali in the fly ash to form calcium sulfite and calcium sulfate. The flue gas containing the fly ash and the calcium sulfite/sulfate then exits the absorber vessel and enters the particulate collection equipment where the majority of the ash and calcium sulfite/sulfate are collected. The "scrubbed" flue gas is then directed to the chimney for release into the atmosphere.

A wet FGD system also utilizes an absorber vessel into which the boiler's flue gas is ducted. However, with the wet FGD system, the absorber vessel is located after the particulate control equipment, such that the fly ash collected prior to the wet FGD system does not become part of the wet FGD's solid waste stream. The wet FGD system utilizes limestone, which must be pulverized and mixed with water to form a slurry that is sprayed into the absorber vessel. As the boiler flue gas passes through the limestone slurry spray, a chemical reaction occurs between the SO_2 in the flue gas and the calcium carbonate in the limestone to form calcium sulfite. If oxygen is introduced into the reaction inside the absorber vessel, the calcium sulfite is converted into calcium sulfate, also known as synthetic gypsum. When limestone with a high calcium carbonate purity is used, the resulting synthetic gypsum can be used to manufacture wallboard.

Q. What are the relative advantages and disadvantages of "dry" versus "wet" FGD systems?

A. Dry FGD systems generally have lower initial capital costs and lower O&M costs because they are somewhat simpler in design and require less equipment. However, there are a number of advantages to wet FGD systems. Wet FGDs are generally designed with SO_2 removal efficiencies of 97 percent, while dry FGD SO_2 removal efficiency is generally in the range of 90-95 percent. Wet FGD allows for a much wider range of coals, which allows more flexibility to purchase lower cost, higher sulfur coals than would be possible with a dry FGD system. Limestone reagent costs are less with wet FGD systems. And, as noted above, unlike dry FGDs which produce byproducts that have no commercial use and generally must be landfilled, wet FGDs produce synthetic gypsum that can be sold and they allow for the continued sale of fly ash. Considering all these factors together, particularly the fuel flexibility associated with wet FGD systems, the total cost of a dry FGD system is greater than the total cost of a wet FGD system.

Q. What NOx emission controls did you evaluate?

A. While NOx emissions can be reduced by burning different fuels, such as natural gas, significant emission reductions can only be made through changes in the combustion process or the addition of post-combustion controls. For this reason, as detailed in Chapter 5 of the Clean Air Report, our analysis of NOx reduction measures focused on combustion modifications and post-combustion controls.

Q. Please explain the difference between combustion and post-combustion NOx controls.

A. Combustion staging is commonly used to control NOx emissions by reducing the amount of nitrogen in the combustion air that is oxidized during combustion, known as "thermal NOx". LNBs and OFA are the commonly used methods to stage combustion. LNBs typically create "zones" of combustion with varying ratios of fuel and combustion air. LNBs are a proven technology for reducing NOx, and are often the initial NOx reduction step taken due to their "low" initial cost, NOx removal effectiveness (approximately 20 to 30 percent), and ease of installation. OFA systems take some of the combustion air that would normally be available to the burners and redirect it so as to enter the combustion process after the initial combustion has occurred at the burners. There are several variations of OFA systems, but their feasibility and NOx reduction efficiency depend upon the specific type of boiler in question.

Post-combustion systems include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems, both of which utilize ammonia-based reagents to promote the conversion of the NOx created during combustion to nitrogen, carbon dioxide and water before it is emitted to the atmosphere. While these technologies generally have higher capital and operating costs, they are also more effective at reducing NOx emissions than LNBs and OFA.

Combinations of combustion modifications and post-combustion technologies are often used for NOx emission control. For instance, installing a relatively low-cost combustion modification, such as LNBs, can reduce the overall capital and operating costs of a post-combustion system such as an SCR. By using LNBs to reduce the NOx levels produced in combustion, the SCR will use less reagent (thus, reducing operating cost) and can be made "smaller" (thus, reducing capital cost), or the SCR can be made the same size and remove more tons of NOx, thus reducing the number of NOx allowances needed.

Q. What mercury emission reduction measures did the Company evaluate?

A. As detailed in Chapter 6 of the Clean Air Report, we evaluated the synergistic mercury reduction effects of NOx, SO_2 and particulate controls, as well as mercury-specific controls such as powdered activated carbon injection technology.

Q. How did you analyze the feasibility and costs of the various control options?

A. We used a number of sources, including studies performed by engineering consultants, internal studies, equipment vendors, and the experience gained from Progress Energy projects which have already been installed or are in progress to assess the cost and feasibility of various compliance options.

Q. What SO_2 emission reduction measures has PEF chosen to pursue in its Integrated Clean Air Compliance Plan?

A. As discussed more fully in Chapter 3 of the Clean Air Report, the SO_2 component of PEF's compliance plan includes installation of wet scrubbers on Crystal River Units 4 and 5, switching Crystal River Units 1 and 2 to burn low-sulfur (1.2 lbs SO_2 per mmBtu) "compliance" coal beginning in 2010, and burning low sulfur oil and natural gas at Anclote Units 1 and 2 starting in 2010. These control options are the lowest incremental cost options available to PEF and provide most, but not all, of the SO_2 emission reductions required. As discussed more fully in Mr. Roeder's testimony and accompanying Clean Air Report, PEF also plans to utilize the SO_2 allowance market as part of the Integrated Clean Air Compliance Plan.

Q. What NOx emission reduction measures has PEF chosen to pursue in its integrated compliance plan?

A. The NOx component of the plan includes the installation of LNBs and SCRs on Crystal River Units 4 and 5, and the installation of LNBs with separated OFA controls on Anclote Units 1 and 2. These control options are among the lowest incremental cost options available to PEF and they provide most, but not all, of the reductions required by CAIR. As discussed more fully in Mr. Roeder's testimony and the Clean Air Report, PEF also plans to utilize the NOx allowance market as part of its Integrated Clean Air Compliance Plan.

Q. How will PEF's compliance plan comply with CAMR?

A. The combination of wet scrubbers and SCRs on Crystal River Units 4 and 5 work together to provide a co-benefit of reducing emissions of mercury. PEF expects mercury emissions to be reduced below the required number of allowances between 2010 and 2017. As discussed more fully in Mr. Roeder's testimony and the Clean Air Report, the Plan also includes installing powdered activated carbon injection systems on Crystal River Unit 2 in 2017 to further reduce mercury emissions in order to achieve CAMR's second phase requirements.

Q. How will PEF's plan comply with CAVR?

A. As discussed above, the final CAVR provides that participation in the CAIR cap-and-trade program may substitute for BART requirements. While additional controls may be required by states for individual units that are shown through modeling to contribute significantly to visibility impairment in a Class I area, PEF expects that installing controls on the larger Crystal River Units 4 and 5 will significantly improve the visibility in Class I areas, more so than installing controls on Crystal River Units 1 and 2, which are the only Crystal River units potentially subject to BART.

Q. What near term investments must the Company make in order to meet the applicable regulatory deadlines?

A. In order to complete the projects included in PEF's Integrated Clean Air Compliance Plan within the planned installation times, the study and design work started in 2005 must be continued, and significant additional engineering and design work must be completed. In addition, construction, water supply and environmental permit applications must be prepared and submitted. PEF also must staff Project and Plant Integration Teams to direct the project work and prepare the plant for operation of the new equipment as it is commissioned.

The primary focus in 2006 will be on the design, engineering, permitting and initial procurement commitments for the Crystal River Unit 4 SCR to achieve a startup date of Spring 2008 and for the Crystal River Unit 5 FGD to achieve a startup date of Spring 2009. Since Units 4 and 5 are virtually identical, the majority of the design and engineering being completed for one unit's FGD or SCR will be applicable to the other unit. Thus, while the focus will be on the FGD and SCR for the unit scheduled for completion first, there will be design and engineering work performed to support the subsequent installations and thereby facilitate the most efficient procurement of equipment and sequencing of construction.

Many of the studies and design work that began in 2005 are continuing into 2006. These studies and other activities are detailed in Chapter 3 of the Clean Air Report. In addition to this study, design and engineering work, procurement commitments will need to be made beginning in mid-summer of 2006 for long lead time equipment, such as induced draft fans, grinding mills, absorber materials, SCR catalyst, gypsum dewatering equipment, controls systems, and others. In addition, PEF will need to contract with various specialty sub-contractors (such as chimney constructors and absorber vessel constructors) in 2006 to ensure their availability to support the construction schedule. Indications are that with the recent amount of activity in these fields as a result of CAIR and CAMR, many of these specialty contractors are already committed to other work and not in a position to accept new contracts.

Q. Are there any uncertainties that may lead to adjustments of the compliance plan in the future?

A. While a significant amount of study, engineering, and analysis has already been completed, there are still outstanding issues that require further investigation. One of the primary issues relates to PEF's Anclote units. During initial development of the compliance plan, PEF assumed that pollution control projects, such as the Anclote LNB/SOFA projects, were exempt from New Source Review (NSR) permitting requirements. As discussed in Chapters 2 and 3 of the Clean AIR Report, however, in 2005 a federal court vacated the NSR exemption for pollution control projects and, effective February 2006, the exemption has been removed from Florida's SIP. As a result, the Anclote LNB/SOFA projects, as well as the Crystal River projects, may now be subject to NSR. Because significant controls will be installed at Crystal River under the current plan, NSR would not be expected to have a major impact for Crystal River. At Anclote, however, the LNB/SOFA projects contemplated for NOx control could potentially increase particulate emissions and thereby trigger NSR. Additional study is needed to determine the magnitude of potential increases, whether additional particulate controls would be needed to meet NSR requirements, and whether the cost of such controls, when combined with the expected costs of the LNB/SOFA systems, would increase the cost per ton of NOx removed above the expected cost of NOx allowances. While CAIR compliance can be achieved by purchasing additional NOx allowances if LNB/SOFA projects are not completed at Anclote, CAVR could require the installation of controls for the reasons discussed in Chapter 2 of the Clean Air Report.

For the Crystal River projects, there are a number of outstanding issues for which studies remain to be completed. Perhaps the most critical action item is completion of the test wells and hydrology studies needed for the consumptive water use permit. As part of the permitting process, PEF will need to determine the quality and sources of limestone and the quality of the FGD makeup water (i.e., freshwater vs. saltwater). These issues are critical factors in determining wastewater treatment and disposal options.

Also for Crystal River, there is uncertainty regarding compliance with CAMR. Although much research and testing is being conducted, including projects with which Progress Energy is involved, much more needs to be determined before compliance with CAMR can be assured. As discussed in Chapter 6 of the Clean Air Report, significant questions remain concerning the effectiveness of current mercury removal technologies, the ability of Continuous Mercury Monitoring Systems to accurately measure and report the mercury emissions from boilers on a long term basis, the levels of mercury in different coals and how the presence of other trace elements in the coal impacts the ability of the various technologies to reduce mercury emissions.

In addition to these specific project and technology uncertainties, there are uncertainties related to the regulations themselves and how DEP and EPA will implement them. While the EPA rules offer guidance, a number of issues remain unresolved, including whether or not cap-and-trade systems will be incorporated for all pollutants (including mercury), the number of NOx (both annual and ozone-season) and mercury allowances that PEF will be allocated initially and in the future, and whether PEF units will need to install additional controls as a result of visibility modeling for nearby Class I areas. As these issues are resolved, PEF will continue to review and, if necessary, adjust its compliance plan to assure timely and cost-effective compliance with all applicable regulations.

Q. In light of the uncertainties you have discussed, are the near term investments you described reasonable and prudent?

A. Absolutely. As discussed above, most of the near term investments relate to SCR and FGD projects at Crystal River Units 4 and 5. These projects provide the greatest amount of emission reductions at the lowest cost per ton removed. For that reason, they will be implemented regardless of the final outcome of DEP's SIP revision process. In addition, by calling for installation of controls on Units 4 and 5 early in the process, PEF's Integrated Clean Air Compliance Plan provides flexibility to install additional controls on other units if necessary to respond to unexpected regulatory developments resulting from DEP's SIP revision process or permitting review for the Anclote projects. All other near-term investments are necessary to ensure that PEF's compliance plan is implemented and, if necessary, adjusted to achieve compliance with the aggressive CAIR/CAMR/CAVR deadlines in a cost-effective manner.

Q. Does this conclude your testimony?

A. Yes, it does.

Progress Energy Florida
Docket No. 060007-EI
Witness: John Holler
Exhibit No. __ (JH-1)

CONCEPTION LEVEL SCHEMATIC OF EMISSION CONTROLS FOR UTILITY BOILERS