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Progress Energy Florida
Integrated Clean Air Compliance Plan

Submitted to the
Florida Public Service Commission

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Progress Energy

Table of Contents

List of Figures

List of Tables

List of Acronyms & Abbreviations

BART .... Best Available Retrofit Technology
BOFA .... boosted overfire air
CAIR .... Clean Air Interstate Rule
CAMR .... Clean Air Mercury Rule
CAPP .... Central Appalachia
CAVR .... Clean Air Visibility Rule
CO_2 .... carbon dioxide
CERA .... Cambridge Energy Research Associates
CCOFA .... close-coupled overfire air
CPVRR .... cumulative present value revenue requirements
DEP .... Florida Department of Environmental Protection
EPA .... U.S. Environmental Protection Agency
EPRI .... Electric Power Research Institute
ESP .... electrostatic precipitator
FF .... fabric filter
FGD .... flue gas desulfurization
FGT .... Florida Gas Transmission Company
FIP .... Federal Implementation Plan
GWh .... gigawatt-hour
Hg .... mercury
lbs/mmBtu .... pounds per million Btu
LNB .... low NOx burners
LNG .... liquified natural gas
LOI .... loss on ignition
MW .... megawatt
MWh .... megawatt-hour
NOx .... nitrogen oxides
NAPP .... Northern Appalachia
NSR .... New Source Review
O&M .... operation and maintenance
OFA .... overfire air
PAC .... powder activated carbon
PEF .... Progress Energy Florida, Inc.
PJFF .... pulse jet fabric filter
PM .... particulate matter
ROFA .... rotating overfire air
SCR .... selective catalytic reduction
SDA .... Spray Dry Absorber
SIP .... State Implementation Plan
SNCR .... selective non-catalytic reduction
SO_2 .... sulfur dioxide
SO_3 .... sulfur trioxide
SOFA .... separated overfire air

Executive Summary

The U.S. Environmental Protection Agency's (EPA's) recent promulgation of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR) poses major new challenges for Progress Energy Florida (PEF). This report presents PEF's Integrated Clean Air Compliance Plan and describes the work performed by PEF to develop the Plan. It outlines the Company's decision-making process and provides a clear understanding of why the Plan was chosen.

The federal CAIR was promulgated in March 2005 and it imposes restrictions on emissions of both sulfur dioxide (SO_2) and nitrogen oxides (NOx) from power plants in 28 eastern states and the District of Columbia through an emissions cap and trade program or other means. CAIR will be implemented in two phases – the first phase beginning in 2010 for SO_2 and 2009 for NOx compliance and the second phase beginning in 2015. When fully implemented in 2015, CAIR is expected to result in a 70 percent reduction in SO_2 emissions and a 65 percent reduction in NOx emissions.

CAMR was also promulgated in March 2005 and it imposes new restrictions on emissions of mercury from coal-fired units through an emissions cap and trade program. CAMR will be implemented in two phases: the first phase beginning in 2010 and the second phase beginning in 2018. When fully implemented in 2018, CAMR will result in a 70 percent reduction in mercury emissions from coal-fired power plants in the U.S.

The EPA finalized amendments to the 1999 regional haze rule in June 2005. Among other things, the final version of CAVR requires states to identify facilities, including power plants, which began operation between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas. To help restore visibility in those areas, states must require the identified facilities to install best available retrofit technology (BART) to control their emissions. Depending on the approach taken by the states, the reductions associated with BART would begin to take effect in 2014. CAVR included EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute. PEF expects that the integrated plan to comply with the CAIR and CAMR will fulfill BART obligations. PEF's "BART-eligible" units are Anclote Unit 1, Bartow Unit 3, and Crystal River Units 1 and 2.

PEF's Integrated Clean Air Compliance Plan, designated later in this report as Plan D, was found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among five alternative plans. The Integrated Clean Air Compliance Plan meets PEF's objectives of (1) meeting all CAIR, CAMR, and CAVR requirements; (2) providing flexibility; (3) managing risk; and (4) controlling costs. This report provides a thorough discussion and analysis of the five alternative compliance plans that were evaluated.

The five plans considered a variety of compliance options including different types of control technologies, fuel switching, and allowance trading. The projected capital costs of the plans range from approximately $570 million to $1.2 billion, excluding AFUDC. AFUDC will increase the overall cost by approximately $62 million to $120 million. At the high cost end of the spectrum, PEF would install scrubbers and SCRs on all four Crystal River units and NOx controls on both Anclote units to be in full compliance with both CAIR and BART. At the low cost end of the spectrum, PEF would install scrubbers and SCRs only on Crystal River Units 1 and 2 and NOx controls on the Anclote units at a capital cost of approximately $570 million to comply with CAVR and rely on fuel switching and allowance purchases for total CAIR compliance. The plan that PEF intends to pursue includes scrubbers and SCRs only on Crystal River Units 4 and 5, NOx controls on Anclote Units 1 and 2, allowance purchases, and fuel switching to comply with CAIR. This Plan relies on the premise that CAIR will satisfy BART requirements. Although the total capital costs for this plan are projected at $736 million (excluding AFUDC), this plan has the lowest total projected costs when all factors are considered including allowance purchases, incremental O&M, and fuel switching. The majority of the capital costs will be incurred in the 2007-2009 time period. There is a great deal of uncertainty, however, surrounding the assumptions supporting these projections and PEF will continue to monitor these assumptions in the future and readjust its compliance plan to ensure that it continues to be the most cost-effective strategy. A summary of the primary components of this Plan are as follows:

SO_2

- Installation of wet scrubbers on Crystal River Units 4 and 5
- Fuel switching at Crystal River Units 1 and 2 to burn low sulfur coal
- Fuel switching at Anclote Units 1 and 2 to burn low sulfur oil and natural gas
- Purchases of SO_2 allowances

NOx

- Installation of low NOx burners and selective catalytic reduction systems (SCRs) at Crystal River Units 4 and 5
- Installation of low NOx burners and Separated over-fire air (LNB/SOFA) at Anclote Units 1 & 2
- Purchase of annual and ozone season allowances

Mercury

- Installation of wet scrubbers and SCRs at Crystal River Units 4 and 5 will provide co-benefit of reducing mercury emissions
- Installation of powdered activated carbon injection on Crystal River Unit 2

The Plan is expected to meet environmental requirements by striking a balance between reducing emissions by adding controls to the largest and newest coal units on the PEF system, and making use of the allowance markets. While a significant amount of study, engineering, and analysis has already been completed to support the development of PEF's Plan, there are still a number of uncertainties and outstanding issues including opacity and particulate emissions, water use permitting, quality and sources of limestone, and effectiveness of mercury removal technologies.

In addition to the project and technology uncertainties surrounding these projects, there is still a great deal of uncertainty associated with the regulations themselves and how the State DEP and US EPA will implement the rules. While the rules as promulgated by the US EPA offer guidance, many of the actual parameters such as the number of Annual NOx, Ozone Season NOx, and Mercury allowances that will be allocated to PEF both initially and in the future, whether or not cap-and-trade systems will be incorporated for all pollutants (including mercury), whether or not compliance with CAIR will satisfy BART, or whether modeling of visibility in nearby Class I areas will require additional controls on PEF's Units are yet to be determined. In the event that the State DEP requires additional measures to satisfy BART, PEF will be placed in the position to install scrubbers on Crystal River Units 1 and 2, which, as previously discussed, will increase the projected capital expenditures. As these parameters are defined through the State Implementation Plan and other means, PEF will continue to review its Plan and adjust it accordingly so as to assure compliance with all applicable regulations with the most cost effective strategy.

Chapter 1 Overview of Report

Introduction

EPA's recent promulgation of CAIR, CAMR, and CAVR poses major new challenges for PEF. CAIR imposes restrictions on emissions of both SO_2 and NOx from utility power plants. CAMR imposes new restrictions on emissions of mercury from PEF's coal-fired units. And CAVR could require retrofit controls on certain of PEF's units to improve visibility in national parks and wilderness areas.

This report presents PEF's Integrated Clean Air Compliance Plan and describes the work performed by PEF to develop the Plan. The purpose of this report is to communicate the Plan and provide a preliminary "roadmap" of the actions and costs necessary to implement the Plan. It outlines the Company's decision-making process and provides a clear understanding of why the Plan was chosen.

The Company will use this Plan to guide internal planning and budgeting efforts. However, compliance planning is a dynamic process as the State of Florida has not fully developed State Implementation Plans for CAIR, CAMR and CAVR. PEF will be improving its knowledge of compliance alternatives and regulatory requirements over time. The Company's Integrated Clean Air Compliance Plan will be adjusted accordingly.

Overview of Compliance Planning Process

An important first step in developing a compliance plan is the development of a thoughtful and complete compliance planning process. The compliance planning process used by PEF is similar to the process used to select the Company's resource plan. The basic steps in the process are as follows:

- Identify compliance options
- Develop cost and operating data of options
- Perform technical and economic screening of options
- Develop alternative compliance plans
- Evaluate plans, including sensitivity analysis on key uncertainties
- Select plan that meets objectives

Objectives and Decision Criteria

PEF's objective was to select a plan that: (1) meets all CAIR, CAMR, and CAVR requirements; (2) manages risk; (3) provides flexibility; and (4) controls costs. These objectives require the Company to balance both cost and risk to select an "optimal" strategy. Each of these objectives can be further defined as follows:

- **Meet environmental requirements**—This objective is straightforward. The Company takes its environmental responsibility seriously and will meet all requirements of the CAIR, CAMR, and CAVR, and all other state and federal environmental regulations.
- **Manage risk**—In making long-term planning decisions, uncertainties are numerous and include the cost of technology options, fuel and allowance markets, and the structure and type of environmental regulations.

- **Provide flexibility**—Strategic flexibility is defined as the ability to change direction based on new information. As plans extend into the future, the possibilities for unforeseen circumstances increase. Therefore, it is important to maintain the ability to alter course based on new information.
- **Control costs**—PEF seeks to achieve compliance using the most cost-effective plan to provide emission reductions at the lowest reasonable cost to its customers.

Identification of Compliance Options

The first step in the compliance planning process was to develop a list of potential compliance options. There are a number of ways to control system emissions. SO_2 emissions can be controlled by switching to lower sulfur fuels and retrofitting FGD systems to coal-fired generating units. Use of lower sulfur oil and natural gas at oil-burning units would also reduce emissions. Finally, purchases of emission allowances are also an option for complying with CAIR. Chapter 4 provides an overview of the various control options investigated by PEF. Chapter 8 of this report discusses the fuel alternatives studied.

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 (such as through the addition of LNBs or OFA) or the addition of post-combustion controls (such as SCRs). A discussion of NOx control options can be found in Chapter 5 of this report.

Mercury emissions can be captured by some of the equipment already on the Company's Crystal River units, and further reductions can be achieved from controls for SO_2 and NOx emissions. Other mercury-specific emission controls are available and under development. Mercury emissions and the potential control options are discussed in Chapter 6.

Technical Studies and Data Development

PEF used a number of sources, including studies performed by engineering consultants, internal studies, equipment vendors, and experience gained from Progress Energy projects that have already been installed or are in progress to assess the cost and feasibility of various compliance options. Other study efforts by the Company included market studies of various coals and transportation methods and an analysis of the range of future prices for emission allowances. The results of these technical studies provided data used in the economic evaluation of the compliance options.

Screening of Emission Control Options

The objective of screening was to eliminate from further consideration those SO_2 and NOx compliance options that did not meet technical criteria or were not economically competitive with other options. Screening was conducted on a unit basis (e.g., options for Crystal River Unit 1) as well as on a system basis to select the most cost-effective options for all units. The end result of the screening were system "supply curves" ranking emission control options based on their incremental cost per ton of pollutant removed. The options that survived both technical and economic screening were considered for strategy development purposes. A detailed description of the methodology for screening is provided in Chapter 11.

Strategy Development and Evaluation

The development of alternative compliance strategies involved two steps. First, the set of options to be considered was developed through screening. Then, a set of alternative compliance plans was developed that differed in terms of the specific units to be controlled and the amount of reliance on allowance purchases for compliance. Five different compliance plans were developed for detailed evaluation. The plans were developed with a focus on reducing emissions during the 2009 through 2025 time period under base case conditions. Additional actions may be required for compliance beyond the year 2025.

The alternative compliance plans were evaluated based on their performance against the quantitative and qualitative decision criteria described above. This consisted of an examination the projected emissions that would result from the various control strategies. The economic costs of the plans were compared in terms of cumulative present value of revenue requirements. The impact on the cost of the plans of uncertain allowance prices and capital costs of control equipment were also studied.

Report Organization

The remainder of this report is organized as follows:

Chapter 2, Background, reviews the CAIR, CAMR, and CAVR regulations and basic system characteristics influencing PEF's compliance decisions.

Chapter 3, Findings and Recommendations, describes the selected plan and why it was chosen.

Chapters 4 and 5 address the cost and technical issues for SO_2 (Chapter 4) and NOx compliance (Chapter 5).

Chapter 6 provides an overview of mercury emissions and mercury reduction technologies.

Chapter 7 discusses CAVR/BART compliance technologies.

Chapter 8 addresses fuel supply alternatives and Chapter 9 discusses emission allowance markets.

Chapter 10 reviews other compliance alternatives investigated by PEF.

Chapters 11 and 12 review the economic screening of compliance options (Chapter 11) and the evaluation process and results of the study (Chapter 12).

Chapter 2 Background

Introduction

This chapter provides background information for PEF's Integrated Clean Air Compliance Plan. The chapter outlines the CAIR, CAMR, and CAVR environmental requirements recently promulgated by EPA. The focus is on the requirements for SO_2, NOx, mercury and visibility imposed by CAIR, CAMR, and CAVR, although other potential environmental requirements are also discussed. This chapter also describes the current system characteristics (such as projected load and energy growth and system emissions) as well as fuel source and generation mix. These features of the Company's system are important as they provide context for the cost and availability of compliance options, and thus, the selected strategy.

Requirements Under the Clean Air Interstate Rule

This section discusses the regulatory requirements of CAIR, which EPA promulgated in March 2005.

General Overview

CAIR was signed by the Acting EPA Administrator on March 10, 2005. CAIR requires significant reductions of SO_2 and NOx from power plants in 28 eastern states and the District of Columbia through an emissions cap-and-trade program or other means. CAIR will be implemented in two phases – the first phase beginning in 2010 for SO_2 and 2009 for NOx compliance, and the second phase beginning in 2015. When fully implemented in 2015, CAIR is expected to result in a 70 percent reduction in SO_2 emissions and a 65 percent reduction in NOx in the affected 28-state region as compared to current emission levels.

Status of CAIR Regulations

CAIR requires affected states to revise their SIPs to ensure achievement of specific emission targets. EPA encourages states to use a model cap-and-trade program included in CAIR, but states have the discretion to adopt alternative control programs to achieve CAIR emission targets. States must submit their SIP revisions to EPA by September 11, 2006. The Florida DEP has begun the CAIR adoption process and plans to comply with the September 2006 SIP submittal deadline.

A group of Florida utilities, including PEF, has challenged EPA's decision to include the state of Florida in the federal CAIR. The legal proceedings will likely not conclude prior to the end of 2006 and the outcome cannot be predicted. In addition, although the Florida DEP has indicated that it intends to adopt SO_2 and NOx cap-and-trade programs to implement CAIR requirements, the details will not be known until DEP finalizes its SIP revision. Under a Federal Implementation Plan (FIP) promulgated by EPA on March 15, 2006, however, the federal SO_2 and NOx cap-and-trade programs will automatically take effect if Florida does not meet the September 2006 SIP deadline.

Although some uncertainty remains as to how CAIR will be implemented in Florida, given the long lead time necessary for installation of pollution control systems, PEF must continue to develop and implement its CAIR compliance plan based on the emission targets and allocation methodologies set forth in the federal CAIR. As discussed below, assuming the federal CAIR rule is upheld, there is little, if any, reason to believe that PEF will be allocated more emission allowances under the final DEP rule than under the EPA cap-and-trade program.

Sulfur Dioxide Requirements

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. Figure 2-4 shows the effective emissions allocations for PEF as a result of CAIR.

Nitrogen Oxides Requirements

CAIR also requires significant reductions in NOx emissions in the affected 28-state region. The reductions will be implemented in two phases – the first phase beginning in 2009 and the second phase beginning in 2015. As with SO_2, CAIR encourages use of a cap-and-trade approach to achieve emissions reductions. Under the EPA model cap-and-trade program, EPA will allocate emissions 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. The 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.

Figure 2-5 shows PEF's anticipated total NOx allocations, assuming Florida implements the EPA cap-and-trade program. PEF calculated these allocations based on the Florida allowance budget and the allocation methodology set forth in the CAIR. The CAIR methodology allocates allowances to specific units based on published heat input data, with downward adjustments to be made in the future based on the number of new units that become subject to the program. In preliminary discussions, DEP has indicated that it is considering a different approach that would provide for heat input-based allocations for the first three years and then phase-in an output-based allocation methodology by 2015. If ultimately adopted, this alternative methodology would reduce PEF's NOx allocations as compared to the EPA approach; thereby, increasing PEF's compliance burden.

Permit Requirements

Each affected facility's Title V air operating permit will be revised to reflect changes required by the final state CAIR. In addition, air construction permits must be obtained prior to the installation of pollution control equipment.

Requirements Under the Clean Air Mercury Rule

This section provides a discussion of the regulatory requirements of CAMR, which was promulgated by EPA in March 2005.

General Overview

The final CAMR was signed by the Acting EPA administrator on March 15, 2005. CAMR requires significant reductions in mercury emissions nation-wide from coal-fired power plants through an emissions cap-and-trade program. CAMR will be implemented in two phases: the first phase beginning in 2010 and the second phase beginning in 2018. When fully implemented in 2018, CAMR will result in a 70 percent reduction in mercury emissions from coal-fired power plants in the U.S. Under CAMR, EPA will allocate mercury emissions allowances to each state that participates in the cap-and-trade program. The participating states will then allocate them to individual coal-fired units.

Status of CAMR Regulation

States are currently in the process of adopting the federal CAMR requirements. States must submit to EPA revisions to their SIPs by November 17, 2006. The Florida DEP has begun the CAMR adoption process and plans to comply with the November 2006 SIP submittal deadline.

Figure 2-6 shows the anticipated total mercury emissions allocations to PEF's Crystal River coal-fired units based on the federal CAMR. In its initial plan for CAMR adoption, 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 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 and not others or by purchasing allowances.

Permit Requirements

Each affected facility's Title V air operating permit will be revised to reflect changes required by the final state mercury rule. In addition, air construction permits must be obtained prior to the installation of pollution control equipment.

Requirements Under the Clean Air Visibility Rule

This section provides a discussion of the regulatory requirements of the Clean Air Visibility Rule (CAVR), which was promulgated by EPA in June 2005.

General Overview

On June 15, 2005, EPA finalized amendments to the 1999 regional haze rule. 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 areas. These areas are designated as Class I, and they include 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.

Status of CAVR Regulation

States are currently in the process of adopting the federal CAVR requirements. States must submit to EPA revisions to their SIPs by December 17, 2007. The Florida DEP has begun the CAVR adoption process and plans to promulgate a BART-related final rule in mid-2006.

BART Requirements

BART requirements apply to facilities that began operation between August 1962 and August 1977. These units are required to install BART for SO_2, NOx and particulate matter. PEF operates four units that are subject to BART, including Anclote Unit 1, Bartow Unit 3, and Crystal River Units 1 and 2.

EPA rule establishes presumptive BART emission limits for coal-fired and oil-fired units greater than 200MW in size. For SO_2, the presumptive limit for coal units is based on use of flue gas desulfurization (FGD or "scrubbers") with a 95 percent removal efficiency or an emissions rate of 0.15 lb SO_2/mmBtu. For oil-fired units such as Anclote Unit 1, the presumptive limit for SO_2 is oil with a sulfur content of less than one percent. For NOx, the EPA presumptive limit for tangential coal-fired boilers such as Crystal River Units 1 and 2 is 0.28 lb NOx/mmBtu. BART for NOx emissions from an oil-fired unit is defined as combustion controls. Particulate matter from coal-fired units is already controlled with electrostatic precipitators (ESPs), and the BART regulation is silent on particulate control for oil-fired units.

The deadline for installing BART controls is no later than 5 years after EPA approval of the state's BART SIP submittal, which is due no later than December 17, 2007. Assuming timely state submittal and EPA approval, the installation deadline would be in the 2013-2014 time frame.

The final CAVR contains a provision that adoption of the CAIR cap-and-trade program for SO_2 and NOx may satisfy the BART requirements for those pollutants. Thus, if the federal CAIR is upheld and DEP adopts the EPA cap-and-trade program, it is conceivable that PEF would 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.

Permit Requirements

DEP has preliminarily proposed that utilities submit BART permit applications for affected units by December 31, 2006. These applications must contain demonstrations that the CAVR BART requirements will be satisfied. Changes resulting from BART implementation will be reflected in amendments to the facilities' Title V air operating permits. In addition, air construction permits must be obtained prior to the installation of pollution control equipment.

Other Environmental Requirements

NPDES Permitting

SCR and FGD systems create wastewater that must be treated and discharged to the environment. A discharge of waste water to surface waters is anticipated. The existing National Pollutant Discharge Elimination System (NPDES) permits for the affected generating units will need to be modified to authorize the discharge of treated wastewater. All discharged waste water generally would need to be treated so that the discharge would not exceed state water quality standards.

Consumptive Use (Water) Permitting

FGD systems require the use of a large amount of freshwater and/or seawater in the pollutant removal process. Freshwater would be withdrawn from the existing underlying freshwater aquifer. Saltwater would most likely be withdrawn from an existing plant intake. The Southwest Florida Water Management District (SWFWMD or District) is the permitting authority for the consumptive use of water at the Crystal River site. Freshwater is a limited and valuable resource that is becoming more difficult to obtain. To procure an authorization for the freshwater withdrawal, an extensive demonstration of need and impact must be made to the District. The District will require that efforts be made to reduce the use of freshwater to the maximum extent possible. This would include the minimization of the existing water use as well as any possible process changes that could result in water conservation. The District also requires consideration of the lowest quality of water that is acceptable. Lower quality saltwater can be used in some FGD systems and, therefore, will need to be addressed as a potential alternative to freshwater during the consumptive use permitting process.

NSR Permitting

Under DEP's NSR permitting program, preconstruction air permits are required for plant modifications that result in significant increases in certain air pollutants. One condition of NSR permitting is to install Best Available Control Technology (BACT) for emission increases above specific threshold levels. Historically, pollution control projects were exempt from NSR permitting. In 2005, however, a federal appeals court vacated the NSR exemption for pollution control projects and, effective February 2006, the exemption was removed from Florida's SIP. As a result, NOx or SO_2 control projects included in PEF's compliance plan may now be subject to NSR review if they result in significant increases in other pollutants, such as particulate matter.

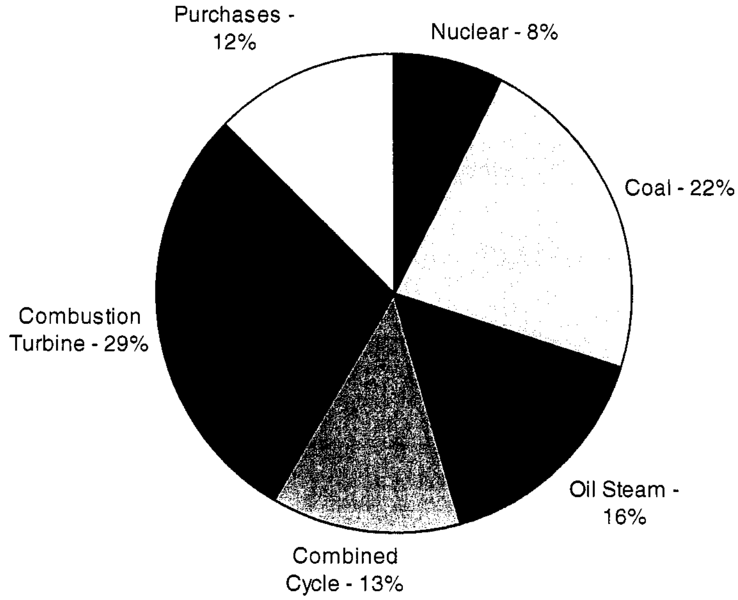
Planning Environment

This section provides background information regarding PEF's generating system, projected generation, and baseline emissions. System characteristics are important because they influence the realm of compliance alternatives and the overall cost of compliance.

Generating System Characteristics

Generating resources utilized by PEF represent a diverse mix of generation technologies and fuel types. Generating resources include nuclear, coal and oil-fired steam units, gas-fired combined cycle units, gas- and oil-fired combustion turbines, and purchases from other utilities and from non-utility generators. The diversity of these resources, shown in Figure 2-1, demonstrates the Company's commitment to minimizing risk and providing economical electricity to customers.

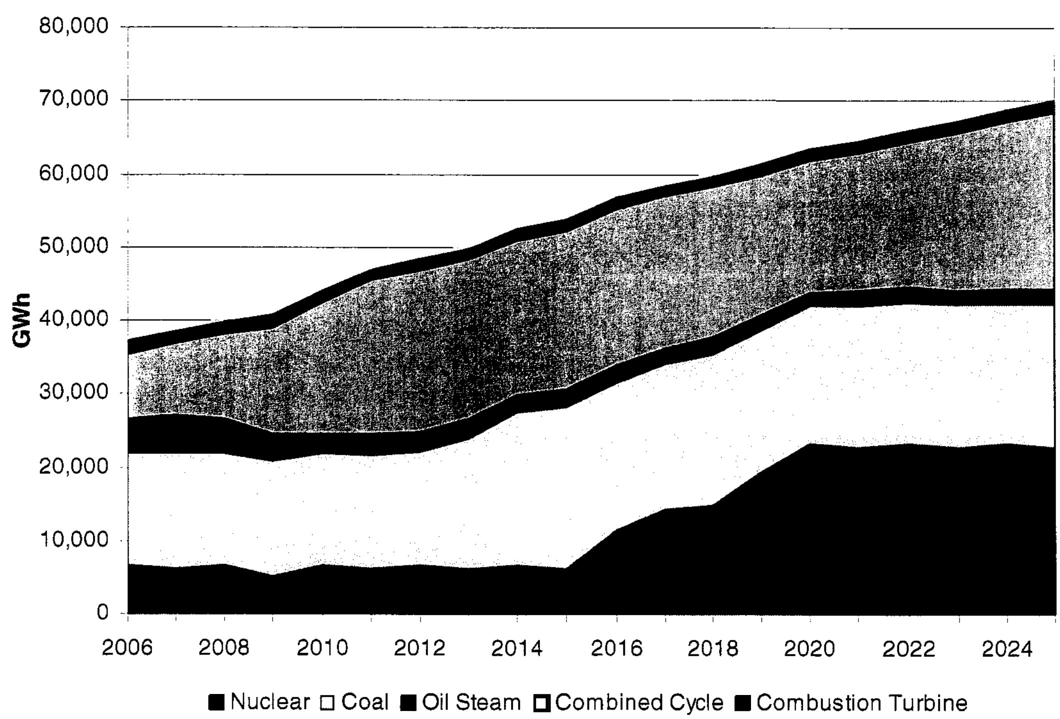
Figure 2-1. PEF Existing Resources Capacity Mix



Projected System Growth and Generation Requirements

Even with aggressive demand-side management efforts, significant growth in electricity use is still expected. Net energy for load is expected to increase by 2.4 percent per year from 2006-2025. Figure 2-2 shows the projected generation of PEF's existing and planned facilities through 2025.

Figure 2-2. PEF Projected Generation

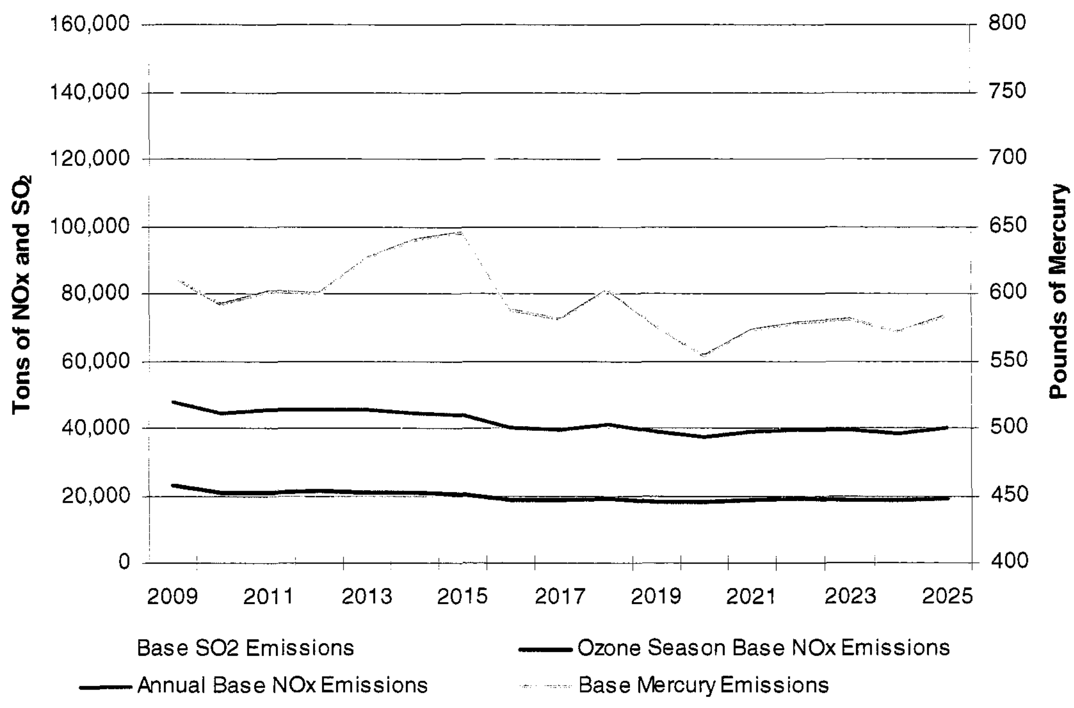


As shown in the figure, the majority of the Company's generation comes from nuclear, coal, and combined cycle plants. The projected generation includes new generating units being planned to be installed during the next 20 years, including two new coal units and two new nuclear units. The figure shows the amount of coal-fired generation to stay relatively constant at approximately 15,000 gigawatt-hours (GWh) per year until 2013, when it increases for a few years until the Company's planned nuclear units come on-line, and then stays relatively constant at roughly 19,500 GWh per year. The amount of gas-fired combined cycle generation increases through 2013 when the first new coal units are installed, and then stays constant until late in the 20-year planning period.

Projected System Emissions

Understanding the changes in the composition of the generation mix is key to understanding the projections of SO_2, NOx, and mercury emissions. Figure 2-3 shows PEF's projected NOx (annual and ozone season), SO_2, and mercury emissions. The figure shows projected baseline emissions to decrease over the next 20 years prior to any additional controls on existing units. The biggest reason for the decrease in projected emissions is the addition of two nuclear units beginning in 2016 in the resource plan. This can clearly be seen in Figure 2-3.

Figure 2-3. PEF Projected Emissions



While projected emissions may be decreasing over time, the projected emissions are still much greater than the allowances allocated to the Company under CAIR and CAMR. Figures 2-4 through 2-6 demonstrate the significant reductions that will have to be made by PEF to comply with these regulations. SO_2 emissions will need to be reduced between 66,000 tons and 84,000 tons, but generally around 72,000 tons per year. In Figure 2-4, the number of allowances to be received by the Company has been reduced by the CAIR factors and is shown as emission-equivalent allowances. For NOx, annual required reductions range from a high of approximately 28,000 tons to a low of 21,000 tons. During the ozone season, required reductions range between 11,000 and 14,000 tons. Approximately 130 pounds of mercury will need to be eliminated annually between 2010 and 2017. Starting in 2018 when the number of allowances is reduced, the Company will be required to reduce its projected mercury emissions by around 390 pounds per year. While the discussion here, and in other places throughout this report, refers to PEF making emission reductions, under the cap-and-trade provisions of CAIR and CAMR, the Company could offset emission reductions by purchasing allowances. PEF's compliance strategy is to develop a cost-effective compliance plan that takes into account costs and risks associated with both installing emission controls and purchasing allowances.

Figure 2-4. Projected SO_2 Emissions and Emission-equivalent Allowances

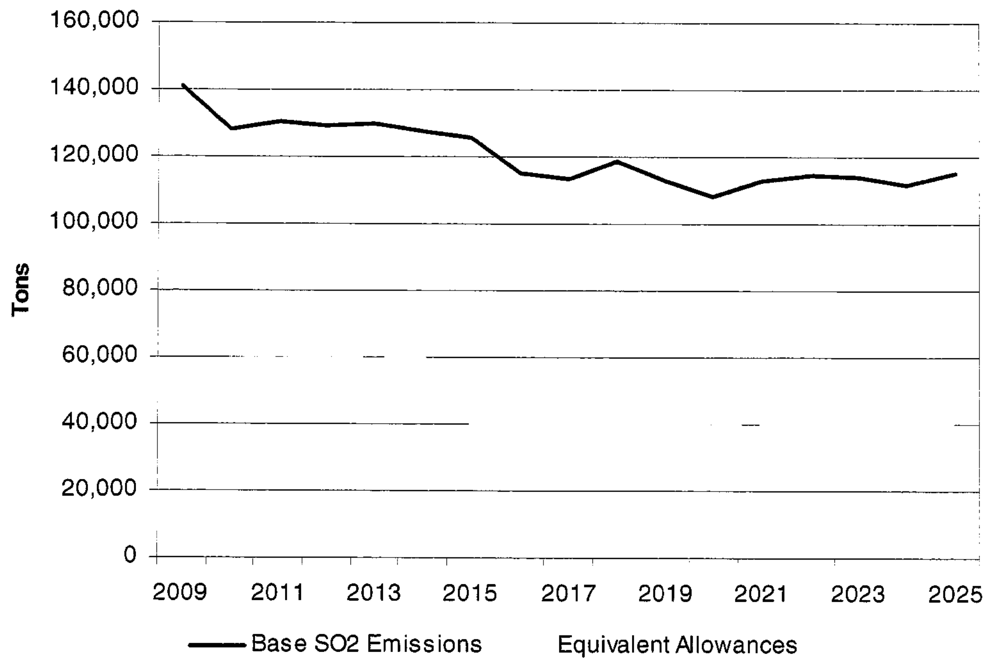


Figure 2-5. Projected NOx Emissions and Allowances

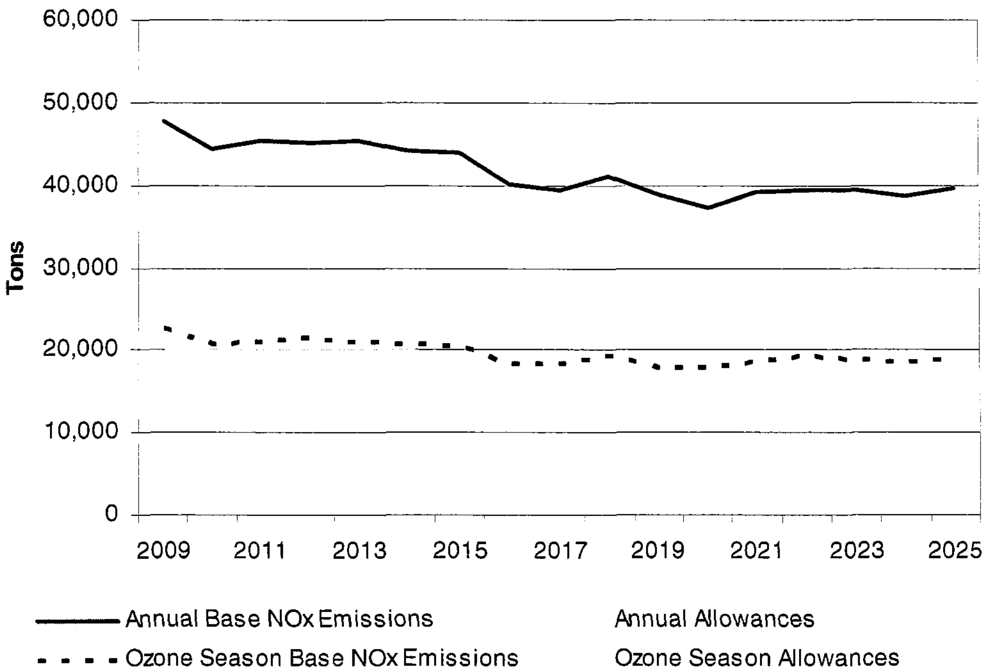
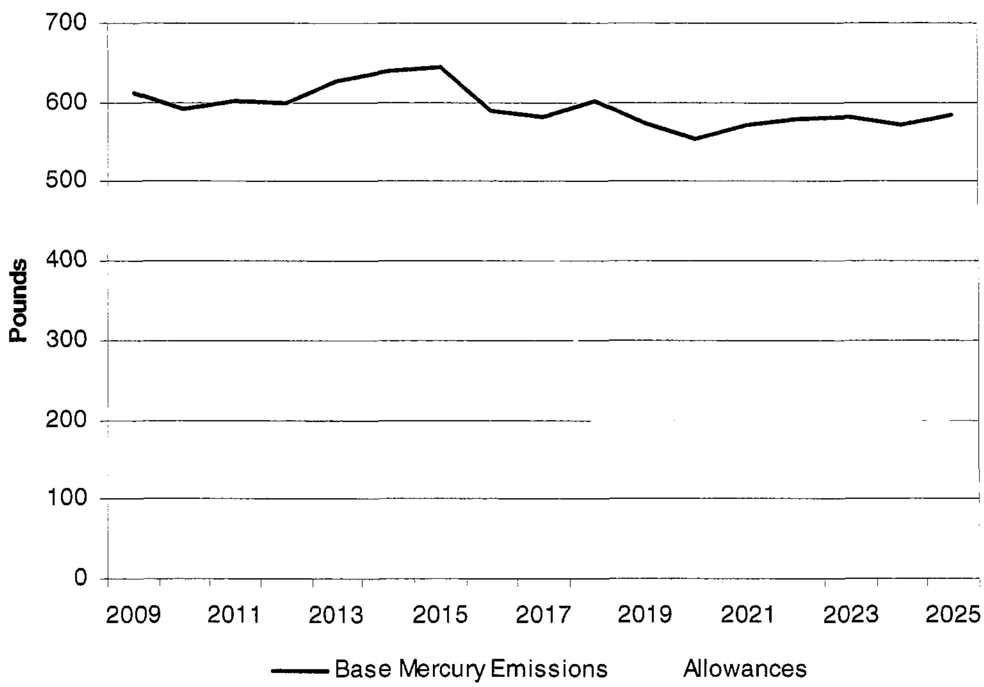


Figure 2-6. Projected Mercury Emissions and Allowances



Prior to developing the Company's strategy to reduce SO_2, NOx, and mercury emissions, it is necessary to understand from which units the emissions are being produced. Figure 2-7 shows the projected SO_2 emissions by unit type. As can be seen in the figure, PEF's four coal units at Crystal River produce approximately 75-80 percent of the Company's SO_2 emissions, with much of the remaining emissions being produced by the Anclote oil-fired steam units. The figure shows that Crystal River Units 4 and 5 produce more than 50 percent of the coal-based SO_2 emissions, even though they currently burn low sulfur compliance coal. It is clear from this figure that if the Company is to reduce its SO_2 emissions below the allowance levels set by CAIR, emissions from the Crystal River units, particularly units 4 and 5, will need to be significantly reduced. In essence, the Company will need to eliminate the equivalent of all of the emissions from Crystal River 4 and 5, the two Anclote units, and the Company's future planned coal units. Since *all* of the emissions from these units cannot be eliminated, the emissions from Crystal River Units 1 and 2 would also need to be reduced to get below allowance levels set by CAIR.

Figure 2-7. Projected SO_2 Emissions by Unit Type

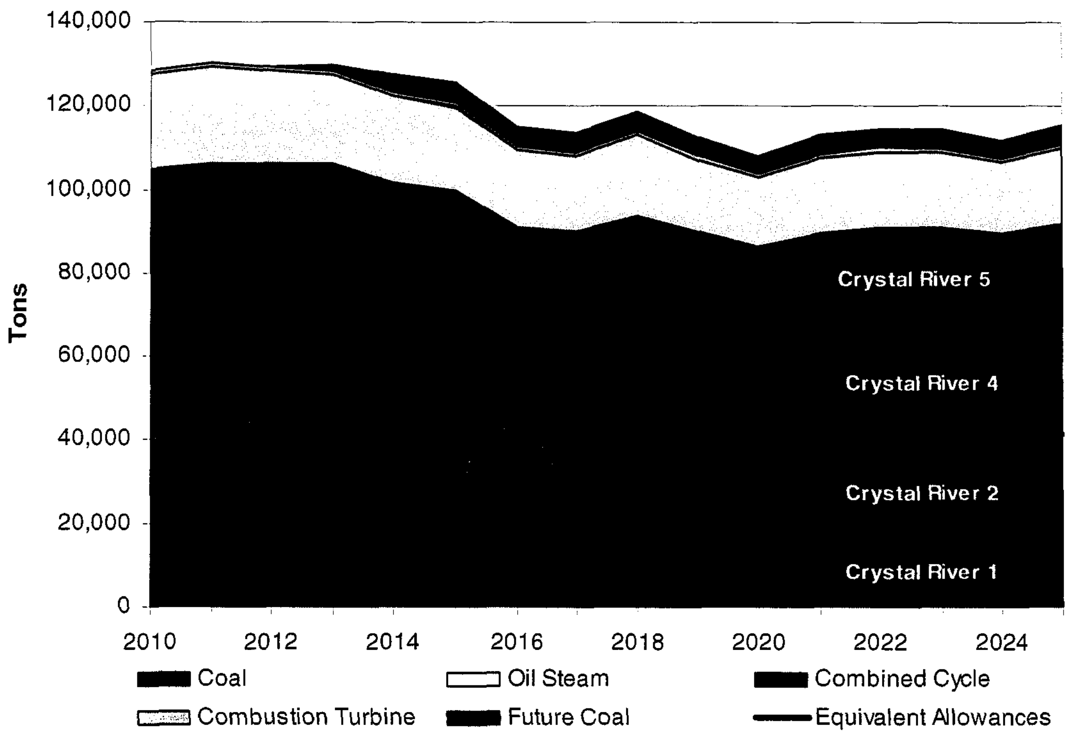


Figure 2-8 shows the projected annual NOx emissions by unit type. As with SO_2, the coal units produce approximately 75-80 percent of the Company's NOx emissions. Because the production of NOx is largely due to the nitrogen in the air and less a function of the type of fuel burned, the combined cycle and combustion turbine units produce more measurable quantities of NOx than SO_2. As with SO_2, the largest contributors to the Company's NOx emissions are the Crystal River units, particularly Units 4 and 5. Unlike SO_2, however, Units 4 and 5 produce significantly more NOx than Units 1 and 2, because Units 4 and 5 are almost twice as large as Units 1 and 2 and because Units 1 and 2 already have low NOx burners installed to meet their Title V Permit limits. It is clear from this figure that if the Company is to reduce its NOx emissions below the number of allowances provided by CAIR, emissions from the Crystal River units, particularly units 4 and 5, will need to be significantly reduced. In essence, the Company will need to eliminate roughly the equivalent of all of the emissions from Crystal River 5, the two Anclote and three Suwannee River oil-fired steam units, all PEF's combustion turbines, and the

Company's future planned coal units. Since it is impossible to eliminate all of the NOx emissions from all of those plants, PEF will likely need to significantly reduce NOx emissions from Crystal River Units 4 and 5 and other units to achieve CAIR requirements.

Figure 2-8. Projected NOx Emissions by Unit Type

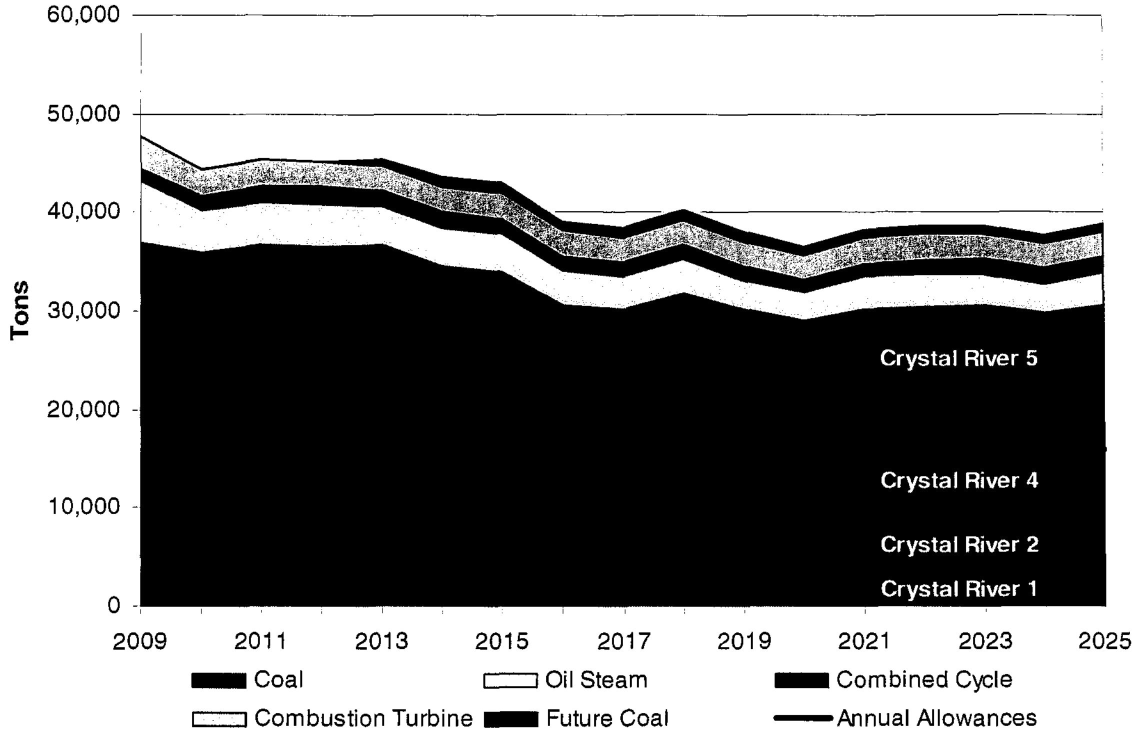
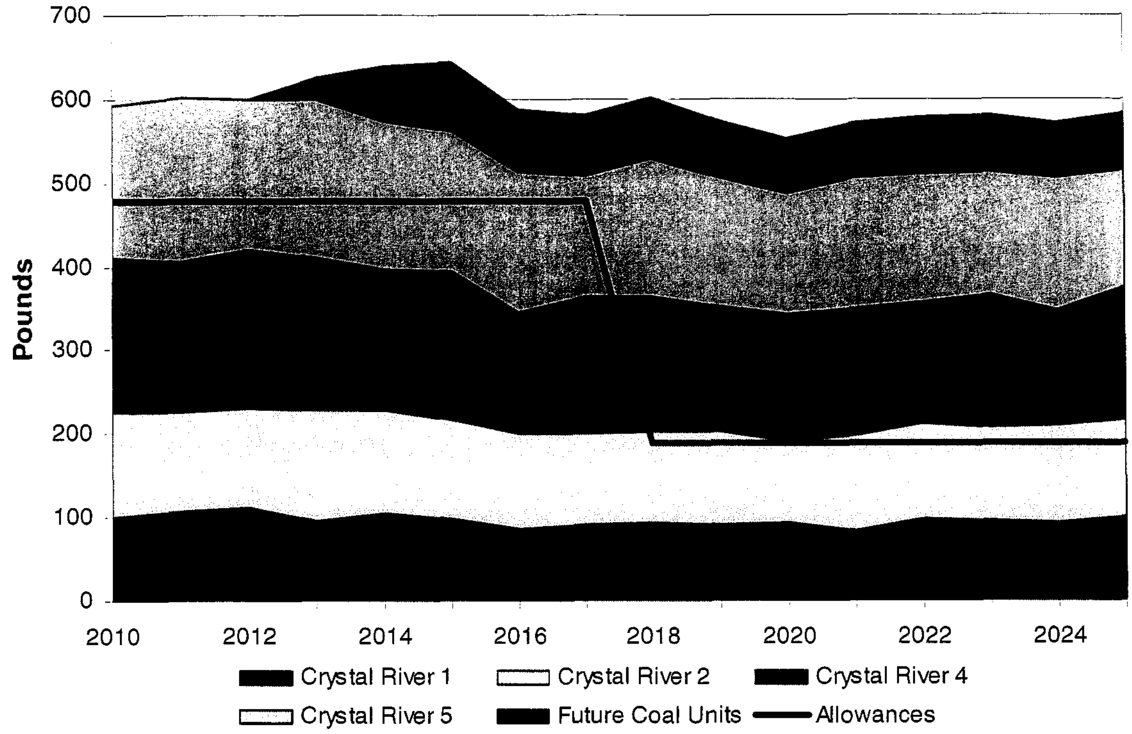


Figure 2-9 provides the projection of PEF's baseline mercury emissions by its coal units subject to CAMR. As the figure demonstrates, in the long term, PEF must eliminate the equivalent of all of its emissions of mercury from Crystal River Units 4 and 5 and the future planned coal units. Since it is impossible to eliminate all the mercury emissions from a unit, a compliance plan will likely require mercury emission controls on most, if not all, of PEF's coal units.

Figure 2-9. Projected Mercury Emissions by Unit



Chapter 3 Findings & Recommendations

After a thorough review of emission control technologies, PEF developed and evaluated five alternative, integrated plans to provide for compliance with CAIR, CAMR, and CAVR. This chapter describes the selected plan and the components of PEF's Integrated Clean Air Compliance Plan, the near-term actions and investments required to ensure an effective implementation of the Plan, the projected overall costs of the plan, outstanding issues, and additional studies and activities.

Integrated Clean Air Compliance Plan

PEF's Integrated Clean Air Compliance Plan, designated in this report as Plan D, was found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among five alternative plans. The Integrated Clean Air Compliance Plan meets PEF's objectives of (1) meeting all CAIR, CAMR, and CAVR requirements; (2) providing flexibility; (3) managing risk; and (4) controlling costs.

The Plan meets environmental requirements by striking a good balance between reducing emissions, through installation of controls on PEF's largest and newest coal units, and making use of the allowance markets to comply with CAIR requirements. The Plan complies with CAMR by reducing mercury emissions through the synergistic effect of wet scrubbers and SCRs on Crystal River Units 4 and 5. Emission reductions are greater than required in the early years, allowing PEF to "bank" emission allowances for use later in time. To reduce mercury emissions further and remain in compliance through 2025, PAC injection controls will be added to Crystal River Unit 2 prior to 2018.

The Integrated Clean Air Compliance Plan provides flexibility by making use of allowance markets to account for a small portion of the reductions required by CAIR. Because of the controls added in the Plan, PEF would need to purchase a minimal number of allowances through 2014. This should provide time for the allowance markets to stabilize, or at least for some of the uncertainties to be resolved. Should it appear that allowance prices are going to be high after 2014, the Plan provides PEF with the ability to add controls to additional Crystal River units at a future date, possibly taking advantage of any technology improvements that may be made. The Plan also allows time for mercury control technologies to advance. As discussed in Chapter 2, the final State Implementation Plans have yet to be developed. The Plan provides time for the rules and regulations to be finalized, at which time PEF can fine-tune the Plan, if necessary. Finally, should PEF experience higher load growth than expected, or if plans for future baseload units change, PEF can then add controls on Crystal River Units 1 and 2, if necessary. Thus, the Integrated Clean Air Compliance Plan enables PEF to manage its risks.

As seen in the quantitative evaluation of the plans, the Integrated Clean Air Compliance Plan is the lowest cost plan under the base assumptions and also when considering allowance price and capital cost uncertainties. Thus, the Plan is the most cost-effective plan to provide emission reductions at the lowest reasonable cost to PEF's customers.

SO_2 Plan

The most significant component of PEF's Integrated Clean Air Compliance Plan is the installation of wet scrubbers on Crystal River Units 4 and 5. The plan includes switching Crystal River Units 1 and 2 to burn low-sulfur (1.2 lbs SO_2/mmBtu) "compliance" coal beginning in 2010, and burning low sulfur oil and natural gas at Anclote Units 1 and 2 starting in 2010. PEF has assumed fuel switching to take place in the analyses described in this report. However, the final decision to switch fuels will be made closer to implementation time. The fuel to be burned by PEF at these units will be that which has the lowest overall cost when the cost of allowances is factored into the overall cost.

The control options utilized in this plan are among the lowest incremental cost options available to PEF and provide most, but not all, of the SO_2 emission reductions required. By pursuing these options, PEF will reduce SO_2 emissions below the level of allowances expected to be received each year through 2014. Assuming these allowances are banked for future use, PEF does not anticipate having to purchase any SO_2 allowances prior to 2024. To achieve compliance with CAIR, starting in 2024 PEF plans to make use of the allowance market to purchase an anticipated 15,000 allowances per year.

NOx Plan

The primary component of PEF's Integrated Clean Air Compliance Plan is the installation of LNBs and SCR systems on Crystal River Units 4 and 5. Currently, the Plan also includes LNB/SOFA controls to be installed on the Anclote units for NOx reductions. However, as noted below, additional study of this option is required. These control options are among the lowest incremental cost options available, and provide most, but not all, of the NOx reductions required by CAIR. To achieve compliance with CAIR, PEF plans to take advantage of the cap-and-trade feature of CAIR by purchasing approximately 3,000 annual and 1,500 ozone season NOx allowances each year after 2015. Because controls can not be installed in time to meet CAIR's NOx requirements in 2009, PEF also plans to purchase approximately 6,000 allowances in that year. A small amount of allowance purchases are also expected to be made between 2010 and 2015.

Mercury Plan

Installation of wet scrubbers and SCRs on Crystal River Units 4 and 5 will provide a co-benefit of reducing emissions of mercury. PEF expects mercury emissions reductions to be greater than required between 2010 and 2017, and the Integrated Clean Air Compliance Plan relies on being able to bank the excess reductions for use in later years. The Plan also includes installing PAC injection systems with additional polishing filters on Crystal River Unit 2 in 2017 to further reduce mercury emissions. The polishing filters will provide PEF the ability to continue selling the fly ash produced rather than disposing of the ash in a landfill, thereby avoiding additional landfill costs. As 2017 is more than 10 years away, PEF will continue to monitor the research and development of mercury control technologies and will choose the most reliable and cost-effective control technology when the time arrives.

Visibility Plan

PEF operates three units that are subject to BART, including Anclote Unit 1 and Crystal River Units 1 and 2 (Bartow Unit 3 is also subject to BART, but is being repowered and is not included in the discussion here). As discussed above, the Integrated Clean Air Compliance Plan includes switching to a low-sulfur oil and the installation of LNBs at Anclote Unit 1, which will bring Anclote Unit 1 into compliance with CAVR. The final CAVR provides that states adopting the CAIR cap-and-trade program for SO_2 and NOx may satisfy the BART requirements for those pollutants. Since PEF's Plan will demonstrate compliance with CAIR, PEF believes it will thus be in compliance with the CAVR. 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 would controlling emissions on Units 1 and 2 at Crystal River.

Near-Term Actions and Investments

In order to complete the projects that have been included in PEF's Integrated Clean Air Compliance Plan in accordance with the planned installation times, study and design work that was started in 2005 must be continued. In addition, significant engineering and design work must be completed in 2006. Initial procurement commitments must be made for long lead time equipment in 2006. Contracting agreements must be executed with the engineering, equipment supply and construction companies that will be performing the work. Construction, water supply and environmental permit applications must be prepared and submitted. And PEF 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 the Crystal River Unit 5 FGD to achieve a startup date of Spring 2009. Because 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, additional design and engineering work will be performed to support the subsequent installations and 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. The studies and activities in progress include:

1. Analyses of fresh-water sources and FGD designs to minimize freshwater requirements, including use of seawater for FGD makeup. As further discussed in the "Outstanding Issues" section below, this will include the installation of a test well to provide a vertical profile of the sulfates and chlorides in the local groundwater to support the consumptive water use permit application;
2. Assessment and testing of limestone samples from various sources, and negotiation of supply contracts;
3. Issuance of a Request for Proposals to wallboard manufacturers and gypsum marketers and negotiation of a contract for disposal of the gypsum produced by the FGD systems;
4. A study to determine the optimal method of supplying urea (for conversion to ammonia for the SCRs) and negotiation of urea supply contracts.

5. A traffic study to determine the amount of additional truck traffic in the local area, and evaluation of new access ways to accommodate both the additional truck traffic and the construction worker traffic during the construction of the FGD and SCR systems, as well as during the Crystal River Unit 3 Nuclear Plant steam generator replacement in the Fall of 2009. In conjunction with the traffic study, Nuclear Security requirements such as Vehicle Barrier Systems and site access inspections will be evaluated to determine more efficient ways to accommodate the additional truck traffic and construction worker access to the site.
6. Studies associated with FGD wastewater streams, including treatment and discharge alternatives.
7. Development of design criteria, such as expected fuel quality, limestone quality, water quality, wind loadings, removal efficiencies, spare equipment philosophy, etc.
8. Development of a general arrangement "drawing" (actually a computer model of the overall site with all of the new equipment and facilities shown in their proposed locations) for use throughout the design and review process.
9. Studies to determine which existing equipment can be reused, which can be upgraded, and which will need replaced. These studies include evaluation of the induced draft fans, air heaters, ESPs, boiler and ductwork stiffening, and the steam turbine cycle to determine if the capacity of the generating units can be increased to offset at least some of the station service load that will be needed by the new FGD and SCR equipment.
10. Studies to determine the most cost effective designs for the installation of new equipment such as chimneys, FGD absorber vessels, limestone receiving, handling and grinding equipment, and common urea receiving and storage systems that would initially accommodate Crystal River Units 4 and 5 and be expandable for Units 1 and 2 if needed in the future.
11. Design of the SCR systems, including initial designs for the reactors and catalyst, urea receiving and storage systems, urea to ammonia conversion systems, ammonia injection systems, economizer and SCR bypass systems and associated ductwork, induced draft fans and associated ductwork, and the foundations, structural steel, and electrical services needed to support SCR installation.
12. Design of the FGD systems, including design of the absorber vessels and internal spray headers, sizing of recycle pumps and oxidation air blowers, sizing of the limestone receiving, storage and grinding equipment, and sizing of the gypsum dewatering systems.
13. Initial designs of various wastewater treatment systems, water supply systems, access roadways, Nuclear Security systems, and piping and conveyor bridges.
14. Study, design and engineering work to support permit applications (construction, air, consumptive water use, solid waste and wastewater disposal among others) that will be needed for the construction of the projects and operation of the units with the new systems installed. It is anticipated that the first permit applications will be submitted in the April-May 2006 time period.
15. Study, design and engineering work to be used in developing a functional specification and issuing a Request for Proposals from selected contractors for the construction of the projects.

16. As explained more fully in the "Outstanding Issues" section below, additional study work to determine potential regulatory implications associated with the Anclote NOx reduction strategy.

In addition to the study, design, and engineering work listed above, 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, and controls systems. Likewise, 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.

Projected Costs of Selected Plan

The Integrated Clean Air Compliance Plan will require capital expenditures and will result in changes in operating costs. Table 3-1 summarizes projected capital expenditures (nominal dollars, excluding AFUDC) for SO_2, NOx and mercury controls.

Table 3-1. Integrated Clean Air Compliance Plan Capital Expenditures

	$ Millions
SO_2 controls	484
NOx controls	220
Mercury controls	31
Total	735

Installation of emission controls will impact future O&M costs. Additional O&M costs will be incurred associated with the wet scrubbers and NOx controls that will be installed at Crystal River and Anclote. The increase in O&M costs is expected to be somewhat balanced by decreases in fuel and purchased power costs. Fuel costs will increase for the Anclote units and for Crystal River Units 1 and 2 as they begin to burn lower sulfur fuels; however, those higher costs will be offset by the savings associated with burning lower cost, higher sulfur coal at Crystal River Units 4 and 5.

Outstanding Issues and Additional Studies

While a significant amount of study, engineering, and analysis has already been completed to support the development of PEF's Integrated Clean Air Compliance Plan, a number of outstanding issues 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 proposed Anclote LNB/SOFA projects, would be exempt from NSR permitting requirements. In 2005, however, a federal appeals court vacated the NSR exemption for pollution control projects. As a result, the Anclote LNB/SOFA projects, (as well as the Crystal River projects), may now be subject to NSR review. Because significant controls will be installed at Crystal River under the current plan, the NSR review is not expected to have a major impact for Crystal River. At Anclote, however, information provided by vendors indicates that while LNB/SOFA installations are effective at reducing NOx emissions, they also have the potential to increase particulate emissions. Additional study is needed to determine the magnitude of potential increases, whether additional particulate controls would be needed to meet NSR standards, 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, compliance with the CAVR/BART rule could require the installation of combustion controls to reduce NOx emissions at Anclote Unit 1 prior to the expected CAVR/BART compliance deadline in 2013-2014.

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

Also for Crystal River, there is uncertainty regarding compliance CAMR implementation. Although much research and testing is underway, including projects with which PEF is involved, much more must be determined before compliance with CAMR can be assured. Significant questions remain regarding the effectiveness of current mercury removal technologies, the ability of Continuous Emissions 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.

Besides these specific project and technology uncertainties, there are uncertainties related to the regulations themselves and how the Florida DEP and the federal EPA will implement them. While the EPA rules offer guidance, a number of issues remain unresolved, including whether Florida will adopt cap-and-trade systems for all pollutants (including mercury), the number of allowances PEF will be allocated both initially and in the future for SO_2, NOx (annual and ozone season) and mercury, and whether PEF units will need to install BART controls as a result of visibility modeling for nearby Class I areas. As these issues are resolved through the SIP revisions and permitting processes, PEF will continue to review and, if necessary, adjust its Integrated Clean Air Compliance Plan to assure cost cost-effective compliance with all applicable regulations.

Chapter 4 Overview of Sulfur Dioxide Reduction Technologies

Introduction

This Chapter provides information on the SO_2 reduction technologies that have been considered for the PEF CAIR/CAMR Compliance Strategy.

PEF SO_2 Emissions

As shown in Chapter 2, the Anclote and Crystal River Units are the largest contributors to PEF's SO_2 emissions total. All of the other PEF units (including the three Suwannee River oil-fired units, the Hines combined cycle gas-fired units, and the numerous simple cycle gas- and/or oil-fired combustion turbine units) contribute only two percent of PEF's total SO_2 emissions. For these reasons, this chapter focuses on the technologies available for the Crystal River and Anclote units.

Unit Descriptions & SO_2 Characteristics

Crystal River Units 1 and 2 are similar units that utilize boilers provided by Combustion Engineering (CE, now a part of Alstom). Each unit burns bituminous coal with Unit 1 nominally rated at 400 megawatts (MW) and Unit 2 nominally rated at 500 MW. These boilers are "tangentially-fired" which means that all of the coal burners are mounted vertically in the four corners of the boilers rather than in the walls of the boilers. SO_2 emissions from these units are currently limited to 2.1 lbs SO_2/mmBtu by the Title V Air Operation Permit.

Crystal River Units 4 and 5 are virtually identical units that utilize Babcock and Wilcox (B&W) boilers. Each unit burns pulverized bituminous coal and each is nominally rated at 740 MW. The boilers are "wall-fired" which means that all of the coal burners are mounted in the boiler waterwalls. Each boiler has 54 coal burners, arranged in six rows of nine burners per row, with three rows in the rear boiler wall, and three rows in the front wall. SO_2 emissions from these units are currently limited to 1.2 lbs SO_2/mmBtu by the Title V Air Operation Permit.

Anclote Units 1 and 2 are nearly identical units that also utilize boilers provided by CE. These units are primarily fired with residual oil, but have the capability of burning natural gas (when available) up to 40 percent of the total heat input to the boilers. The units are nominally rated at 500 MW and also have the tangential arrangement of burners. There are five elevations of oil burners in each corner of the boiler, for a total of 20 oil burners per boiler. These units are permitted to burn residual fuel oil with an annual average SO_2 content of 1.5 lbs SO_2/mmBtu.

Controlling SO_2 Emissions from Oil- and Coal-Fired Units

As SO_2 emissions are directly related to the sulfur content of the fuel being burned, compliance with existing SO_2 permit limits has been accomplished by purchasing fuels with the sulfur content necessary to remain within the limit. For the oil-fired units at Anclote, SO_2 emissions have been controlled primarily by purchasing lower sulfur fuel oils. Also, SO_2 emissions are reduced from these units whenever natural gas, which has essentially no sulfur, is burned in place of fuel oil. The use of lower sulfur fuel oil and natural gas to further reduce SO_2 emissions to comply with CAIR is included in the economic evaluation of compliance options. For the coal-fired units at Crystal River, compliance with existing SO_2 limits has also been accomplished by purchasing fuels with the appropriate sulfur content. As noted above, Crystal River Units 4 and 5 currently burn a lower sulfur "compliance" bituminous coal, which has an SO_2 level of 1.2 lbs/mmBtu or less, while Crystal River Units 1 and 2 burn coals of approximately 1.8 lbs/mmBtu sulfur content. Further reductions in SO_2 emissions by utilizing the "compliance" coal at Crystal River Units 1 and 2 are included in the economic analysis. However, as lower sulfur levels in the coal can adversely affect the operation of the particulate control equipment used on the Crystal River Units 1 and 2 boilers, testing of the units by burning the lower sulfur coal will need to be performed to confirm that this can be successfully accomplished. The compliance strategy for CAIR also considers technologies to reduce SO_2 emissions beyond what can be achieved with fuel changes alone.

Following are descriptions of the specific SO_2 reduction technologies that have been evaluated for the Crystal River and Anclote Units. In addition to the technical descriptions, Table 4-1 provides a summary of the capital and O&M costs for the applicable technologies. These costs have been developed from a number of sources, including studies performed by engineering consultants, internal studies, information gathered from Progress Energy Carolinas based on the experience gained from projects that have already been installed or are in progress, and information supplied by vendors of SO_2 reduction equipment. These cost estimates should be considered as being +/- 25 percent estimates. Work is currently in progress to develop definitive cost estimates for those projects that have been determined through this analysis as being the most likely to form the basis for the CAIR/CAMR Compliance strategy.

SO_2 Reduction Technologies

While numerous SO_2 reduction technologies have been offered for utility applications, the two most commercially-proven systems for units such as those at the Crystal River and Anclote plants are the spray "dry" FGD system and the "wet" limestone FGD system. FGD systems are also known as "scrubbers", as they "scrub" SO_2 from the flue gas of the boiler. In addition to their capability to remove SO_2 from the boiler's flue gas, scrubbers will also remove mercury and in some cases, sulfur trioxide (SO_3). Mercury removal for compliance with the CAMR is discussed in more detail in Chapter 6, but will be addressed briefly here as well. SO_3 is discussed in more detail in Chapter 5, but will also be mentioned here as part of the technology comparison. A comparison of dry and wet FGD systems follows brief descriptions of each.

Dry FGD Systems

In a dry FGD system, flue gas from the boiler is ducted into a large Spray Dry Absorber (SDA) 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. The ash and calcium sulfite/sulfate collected in the particulate control equipment is removed and must be disposed of in a landfill, as there is currently no commercial use for this product.

PM control equipment plays a vital role in removing SO_2 and it must be capable of handling the combined amounts of ash and calcium sulfite/sulfate. While the particulate can be controlled by either an ESP or a Fabric Filter (FF), most new installations use FFs due to their ability to improve SO_2 removal beyond what an ESP can achieve. In retrofit situations, the existing ESPs (such as at Crystal River) may be used, although SO_2 removal efficiency may not be as great as if FFs were installed, and the ESP may not be capable of handling the higher quantities of material. For units such as Anclote, which have no particulate control equipment, FFs would have to be installed along with the Dry FGD system.

Wet FGD Systems

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. Based on PEF's initial discussions with limestone suppliers and other wet FGD owners in Florida, it is expected that this type of high purity limestone will be readily available for Crystal River. Before the synthetic gypsum can be used for wallboard manufacturing, it must be removed from the absorber vessel and have its moisture content reduced so that it can be handled in the wallboard manufacturing process. The "scrubbed" flue gas is then directed to the chimney for release to the atmosphere.

As with the dry FGD system, the performance of the particulate control equipment is important to wet FGD operation, although for different reasons. Wet FGD systems can be affected by a condition known as "aluminum fluoride blinding", which is thought to be caused by excessive amounts of fly ash carrying over from the particulate control equipment into the absorber of the wet FGD. This "blinding" prevents the limestone slurry from reacting with the SO_2, such that the removal efficiency of the wet FGD is substantially reduced. To reduce the risk of "blinding", the particulate control equipment may need to be upgraded as part of a wet FGD system retrofit project.

Comparison of Wet and Dry FGD Systems

While both wet and dry FGD systems perform similar functions, there are significant differences in their design and operation. These differences will impact not only the capital cost of construction, but also the operating cost for reagents, the amount of power required, the types of fuels that can be used, the amount of water required, and the disposal of the solid wastes generated in the processes. Following is a listing and brief discussion of these differences.

SO_2 Removal Efficiency

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.

Sulfur Levels in the Coal

Dry FGDs are generally used with coals with less than about 1.5 percent sulfur, while wet FGDs can be used for coals with virtually any level of sulfur. Thus the 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.

Initial Capital Costs

As dry FGD systems are somewhat simpler in design and have less equipment (such as limestone preparation and grinding equipment, and gypsum dewatering and drying equipment) and generally do not require a new chimney, as most wet FGDs require, the capital cost of a dry FGD system is less than for a "comparable" wet FGD system. However, if it is determined that a FF is required to achieve the removal efficiency required to be "comparable" to the wet FGD, then the total capital cost for the dry FGD and FF is often greater than for the wet FGD alone.

Reagent Use and Cost

A dry FGD uses about 1.1 tons of lime per ton of SO_2 removed, whereas a wet FGD uses about 1.7 tons of limestone per ton of SO_2 removed. Good quality limestone (with calcium carbonate purity levels that would allow for the production of synthetic wallboard-grade gypsum in the wet FGD system) is readily available in Florida, and the cost of lime is estimated to be approximately 5 times higher than the cost of limestone. Thus reagent costs would be less with the wet FGD.

Solid Waste Disposal

As noted above, with a dry FGD, the solid waste is a combination of the fly ash produced in the boiler and the products of the reaction between the lime and SO_2 in the absorber. As this final product has no commercial use, it generally must be landfilled in an environmentally controlled and permitted disposal site. On the other hand, with the wet FGD, the fly ash is collected prior to the wet FGD. If the fly ash is of adequate quality (as it now is at Crystal River), it can be sold as a cement additive. Synthetic gypsum, the solid waste produced in the wet FGD's absorber, can also be sold instead of landfilled.

Water Usage and Wastewater Treatment

As might be expected, the dry FGD uses less water than the wet FGD. A dry FGD will still use about 70-75 percent as much water as a wet FGD, and the quality of the water can be lower. Whereas the wet FGD requires about 60 percent to 70 percent, depending on coal and water qualities, the dry FGD can use brackish water or even seawater. Also, the dry FGD has minimal wastewater treatment requirements as compared to a wet FGD. As was noted in the discussion of Consumptive Water Use in Chapter 2, SWFWMD requires consideration of the lowest possible quality water that is acceptable and the minimization of freshwater usage. Using seawater as part of the makeup water supply to the wet FGD is technically feasible, but the resulting higher chloride levels in the system require that higher grade materials of construction be used in order to protect the equipment. Also, the use of seawater requires that more of the process water be treated through the wastewater treatment system prior to being discharged. As such, utilizing seawater in place of freshwater as part of the overall makeup requirement of the system will result in higher costs for materials and for larger wastewater treatment facilities than if freshwater alone were used. PEF is currently evaluating the water supply and wastewater treatment options for wet FGDs at Crystal River to determine the costs involved with using seawater to minimize freshwater usage. The intention is to demonstrate to SWFWMD during the permitting process that adequate efforts are being made to minimize freshwater usage so that a Consumptive Use Permit can be issued.

Operating Costs Other than Reagents

With less equipment installed for a dry FGD, operating and maintenance costs are generally less than for a "comparable" wet FGD. Also, as the dry FGD has less equipment to operate, it uses less energy and hence there is less station service usage—or conversely more capacity available to be sold to customers.

SO_3 and Mercury Removal Capabilities

As noted in Chapter 5, SO_3 formation is increased when an SCR is installed and when higher sulfur coals are burned. Depending on the magnitude of the increase, as part of the Air Permitting process SO_3 may need to be controlled. Wet FGDs collect very little SO_3, so that any SO_3 control would need to be accomplished with another technology. However, a dry FGD with an FF is capable of removing the majority of SO_3 from the flue gas, although as noted above, the dry FGD not applicable to higher sulfur coals. As further discussed in Chapter 6, both wet and dry FGDs have the capability to remove mercury from the flue gas of a coal-fired boiler.

Table 4-1. Summary of SO_2 Control Technology Options

	Dry FGD	Wet FGD
SO_2 Reduction %		
Crystal River 1	90	97
Crystal River 2	90	97
Crystal River 4	90	97
Crystal River 5	90	97
Capital Cost ($Millions)		
Crystal River 1	150	171
Crystal River 2	166	191
Crystal River 4	211	243
Crystal River 5	210	241
O&M Cost ($Millions/Yr, levelized, 2005$)		
Crystal River 1	3.1	4.2
Crystal River 2	3.8	5.1
Crystal River 4	5.5	7.0
Crystal River 5	5.2	6.8
Consumables Cost ($Millions/Yr, levelized, 2005$)		
Crystal River 1	6.2	0.9
Crystal River 2	7.4	1.1
Crystal River 4	13.7	2.0
Crystal River 5	13.2	1.9

Chapter 5 Overview of Nitrogen Oxide Reduction Technologies

Introduction

This chapter describes the NOx reduction technologies that PEF has considered in developing its CAIR/CAMR Compliance Strategy. As discussed below, PEF has evaluated numerous combustion and post-combustion NOx control technologies as part of its effort to determine the most cost-effective system-wide compliance strategy.

PEF NOx Emissions

As shown in Chapter 2, the Anclote and Crystal River Units are the largest contributors to PEF's NOx emissions total. With the Bartow units being repowered, and all of the other PEF units (including the 3 Suwannee River oil-fired units, the Hines combined cycle gas-fired units, and the numerous simple cycle gas- and/or oil-fired combustion turbine units) contributing only 4 percent of the NOx emissions, this chapter only focuses on the technologies available for the Crystal River and Anclote units.

Unit Descriptions & NOx Characteristics

Crystal River Units 1 and 2 each have had LNBs and OFA systems installed to meet their current annual permitted NOx emissions limit of 0.4 lbs NOx/mmBtu.

Crystal River Units 4 and 5 still 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 NOx/mmBtu.

Anclote Units 1 and 2 have not had LNBs or OFA systems installed, and the Air Permit for these units has no NOx limit. The units currently operate with NOx emissions averaging approximately 0.34 lbs NOx/mmBtu.

NOx Formation and NOx Reduction Principles

NOx is formed during the combustion of fossil fuels as available sources of nitrogen are oxidized in the immediate vicinity of the flame zone within the boiler. There are two distinct factors that influence the amount of NOx produced. One is the nitrogen content of the fuel, known as "fuel NOx", and the second is the amount of nitrogen in the combustion air that is oxidized during combustion, known as "thermal NOx". The amount of fuel NOx generated is directly related to the nitrogen content of the fuel, and the amount of thermal NOx generated is directly related to both the temperature of the reaction ("flame temperature") and the amount of oxygen available to support the reaction. The typical proportions of fuel NOx and thermal NOx for fossil fuel-fired boilers are as follows:

FUEL	Thermal NOx	Fuel NOx
Natural Gas	100%	0%
Fuel Oil	40%-60%	40%-60%
Pulverized Coal	20%-40%	60%-80%

In general, for a given fuel, the two basic elements that can be used to reduce the NOx produced during combustion are to reduce the peak flame temperature and to limit the amount of oxygen available to the combustion process. This is accomplished in utility boilers by "staging" the combustion. Common boiler operating practice prior to the imposition of NOx limits had been to supply a controlled amount of "excess air" to the combustion process to ensure that there is more than enough oxygen available to completely combust all the fuel. With staging, only enough combustion air is allowed to mix with the fuel as is required to complete the combustion at any given stage in the combustion process. This tends to both lower the flame temperature and make less oxygen available to the process, thus reducing the NOx emissions.

LNBs and OFA are the commonly used methods to stage combustion. LNBs typically create several "zones" of combustion with varying ratios of fuel and combustion air, and OFA systems take some of the combustion air that would normally be available to the burners, and redirects it so as to enter the combustion process after the initial combustion has occurred at the burners. As the effectiveness of these staging processes is highly dependent on the ability to control the air and fuel delivery systems within much tighter parameters than when more excess air was available, modifications to the air and fuel delivery systems and controls are often desirable to get the maximum NOx reductions. Also, while staging can be effective at reducing NOx emissions, it can also have a negative impact on the combustion efficiency of the boiler. By limiting the oxygen available for combustion, staging can result in less of the carbon in the fuel being completely burned. When this occurs, the unburned carbon ends up in the fly ash and the heat available in that carbon does not get utilized. For the oil-fired units, this may also increase the "opacity" (amount of smoke) emitted from the chimney. Of more direct concern for the coal-fired units is that too much unburned carbon in the fly ash will contaminate the fly ash to the extent that it cannot meet the specifications for use as a cement additive, and thus cannot be sold to cement producers. This contamination, known as "loss of ignition" (LOI), is limited to six percent by the cement industry. Fly ash that cannot be sold as a cement additive would likely have to be landfilled, or at best, disposed of as a lower value fill product. Because all of the fly ash from Crystal River Units 4 and 5 is now sold to cement producers, and with limited on-site permitted landfill areas for ash disposal if it is contaminated, it is important that any staging of the combustion for these boilers be done in such a manner as to reduce the risk of contaminating the fly ash.

In addition to staging combustion, NOx emissions reductions from fossil fuel-fired boilers can be accomplished with post-combustion systems. Post-combustion systems include selective non-catalytic reduction (SNCR) and SCR systems, both of which utilize ammonia-based reagents to promote the conversion of the NOx created during combustion to nitrogen, carbon dioxide (CO_2) 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.

Combinations of combustion modifications and post-combustion technologies are often used for compliance with NOx regulations. 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 (reducing operating cost) and can be made "smaller" (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. The combinations that can be considered are unit specific and depend on fuel types, boiler configurations, operating parameters and other factors.

The following sections describe the specific NOx reduction technologies that have been evaluated for the Crystal River and Anclote Units. In addition to the technical descriptions, Table 5-1 provides a summary of the capital and O&M costs for the applicable technologies. These costs have been developed from a number of sources, including studies performed by engineering consultants, internal studies, information gathered from Progress Energy Carolinas based on the experience gained from projects that have already been installed, and information supplied by vendors of NOx reduction equipment. These cost estimates should be considered as being +/- 25 percent estimates. Work is currently in progress to develop definitive cost estimates for those projects that have been determined through this analysis as being the most likely to form the basis for the CAIR/CAMR Compliance strategy.

NOx Reduction Technologies: Combustion Staging

Low-NOx Burners

LNBs are generally capable of approximately 20-30 percent NOx reductions. The actual reduction capability of LNBs is dependent upon a number of factors including the type of fuel being burned, the number of burners being replaced, the ability to measure and control air and fuel flows to individual burners, the physical design of the burners, the load at which the boiler is being operated, and the configuration of the boiler itself. 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, and ease of installation. They are also attractive in that they do not require additional equipment such as fans or ductwork and do not require any reagents. The one concern with LNBs is the possibility of contaminating the fly ash with unburned carbon as noted above. However, vendors are offering LNBs with NOx removal and LOI guarantees that will, with proper tuning, allow for continued fly ash sales. While there are O&M costs associated with LNBs, they would not be expected to be significantly greater than for existing burners, and hence zero incremental O&M costs are assumed in the economic analysis. LNBs for the Anclote boilers will be considered in the discussion of OFA systems that follows.

Overfire Air Systems

There are several variations of OFA systems available for Crystal River Units 4 and 5 and/or the Anclote units. These systems are: Close-Coupled Overfire Air (CCOFA), Separated Overfire Air (SOFA), Boosted Overfire Air (BOFA) and Rotating Overfire Air (ROFA).

Close-Coupled Overfire Air

CCOFA can be used on the tangentially fired units such as Crystal River Units 1 and 2 (where it has already been installed) and Anclote Units 1 and 2. For the Anclote Units, the topmost existing oil burner in each corner of the boiler would be replaced with an air injection port, and the remaining burners would then need to be replaced with higher capacity burners (to make up for the burners being removed) designed for Low-NOx operation. OFA would then be introduced into the boiler above the combustion zone through this new air injection port. The NOx removal efficiency would be approximately 29 percent. However, the required increase in capacity of the remaining burners would exceed the manufacturer's heat input design standards, which could result in localized waterwall tube overheating in the areas adjacent to and above the burners. As the Anclote boilers have experienced overheated tubing in the horizontal superheater section just above the burner areas, the CCOFA system is considered to be a high risk option for long term boiler availability.

Separated Overfire Air

SOFA can be used on both tangentially-fired units, such as Anclote Units 1 and 2, and on wall-fired units, such as Crystal River Units 4 and 5. In either application, air injection ports are installed above the burners, and new ductwork is installed to convey combustion air to the ports. The combustion air is ducted from the existing combustion air ducts, such that additional combustion air fan capacity is generally not needed. However, for units such as Anclote that are near maximum fan capacity when the unit is at full load, some upgrading of the existing fans may be required to maintain full-load capability. The installation of these ports involves installing new waterwall tubing to create a "window" in the wall of the boiler where the injection ports are to be located. For the Anclote units, the NOx removal efficiency would be approximately 41 percent. At Anclote, this system would avoid the potential overheating problems associated with the CCOFA system.

While SOFA systems have been installed on numerous wall-fired boilers, B&W has advised that due to the design of the Crystal River Units 4 and 5 boilers, major boiler modifications (primarily redesigning the front and rear boiler waterwalls and relocating several rows of burners) would be required in order to be able to locate the SOFA ports so that the SOFA system would be effective. Other vendors have proposed SOFA systems for Crystal River Units 4 and 5. NOx reduction efficiencies (assuming that LNBs have already been installed) range from 12 to 25 percent. However, each of the vendors that offered SOFA systems had expected ranges of LOIs that would exceed the six percent limit that the cement producers allow, requiring the fly ash to be land-filled. For these reasons, SOFA is not being considered for Crystal River Units 4 and 5.

Rotating Overfire Air and Boosted Overfire Air

ROFA and BOFA are variations of the SOFA system. Rather than use combustion air ducted from the existing combustion air ducts as with the conventional SOFA system, ROFA and BOFA systems utilize fans to provide higher velocity air to the air injection ports. While potentially more effective than a conventional SOFA system, the capital expense of the required fans, and the ongoing cost of running the fans can be significant factors in the economic evaluation. The primary difference between the ROFA and BOFA systems is that with the BOFA system, the air is injected straight into the boiler combustion zone, while with the ROFA system, air is injected at an angle, such that the air "rotates" in the boiler. The higher velocity air being injected with the BOFA or ROFA system creates more turbulence in the combustion zone, and hence provides for more complete burning of the fuel. Also, the fans for the ROFA system require approximately 3-6 times more horsepower as compared to the BOFA system.

ROFA and BOFA systems were evaluated for the Anclote units. The NOx removal efficiency of the ROFA system would be approximately 35 percent. The NOx removal efficiency of the BOFA system would be approximately 24 percent.

While the ROFA system has been proven on many smaller units (including at Progress Energy plants in North Carolina), and the BOFA system has been installed on smaller units as well, there is limited experience with these systems on units the size of Crystal River Units 4 and 5. Given this limited field experience with these sized units, as well as the overall concerns with OFA systems, including the impact on the salability of the fly ash and the high cost per ton of NOx removed determined from the Anclote screening analysis, neither ROFA nor BOFA were considered to be viable options for Crystal River Units 4 and 5.

NOx Reduction Technologies: Post-Combustion

Selective Non-Catalytic Reduction

SNCR systems inject a reagent, generally either vaporized anhydrous ammonia, aqueous ammonia, or liquid urea (which decomposes to ammonia) into the boiler's combustion gasses to create a chemical reaction that converts the NOx and ammonia into nitrogen, water and CO_2. This chemical reaction occurs in a fairly narrow temperature range of about 1,600-2,100 degrees Fahrenheit. Typically this temperature range is found within the "convective section" of the boiler—that is, in an area of the boiler after the combustion has taken place, but before the combustion gasses have released all their heat energy to the boiler surfaces. Consequently, the reagent injection system must be installed in a relatively confined space in the boiler that is selected based on temperature profile testing of the boiler. Because temperatures within the boiler will change as load changes, the location in the boiler with the optimum temperature for the SNCR system may change, which would necessitate multiple reagent injection systems and temperature measurement and control equipment for operation of the SNCR throughout the boiler's load range. In addition to the temperature constraints, for an SNCR system to operate properly the reagent must be injected so as to be evenly mixed with the combustion gasses. This generally requires an injection "grid"—meaning a series of nozzles spanning the "convective section" of the boiler from side-to-side and top-to-bottom—to be installed inside the boiler. In addition to the injection grid, SNCR systems require storage tanks for the reagent, pumps, piping and valves to transport the reagent to the injection grid, and a control system to monitor and adjust the system's operation as needed.

A variation of the basic SNCR system utilizes natural gas and steam injection along with the ammonia reagent to improve NOx removal efficiency. This type of system was not evaluated for either Crystal River or Anclote for several reasons. At Crystal River, natural gas is not available on site, and Nuclear Security concerns may preclude use of natural gas even if a pipeline to the plant site could be installed. Also, this type of system has only been installed on 200-350 MW units, and would not be considered a proven technology for either the Crystal River or the Anclote-sized units.

The NOx removal efficiency of a typical SNCR system is approximately 20 percent. Higher removal efficiencies up to about 25 to 35 percent can be achieved if more ammonia is made available for the reaction. However, as more ammonia is made available, not all of it will react with the NOx. The unreacted ammonia that carries through the boiler is known as "ammonia slip". High levels of ammonia slip will cause fouling of the boiler's air heaters, necessitating a boiler outage to clean the air heaters, and will contaminate the fly ash to the point that it could not be sold as a cement additive. For these reasons, control of ammonia slip is critical to operation of an SNCR unit.

SNCR systems were not considered for the Anclote units because of the design of the boilers. The Anclote boilers are "positive pressure" boilers, whereas the Crystal River boilers are "negative pressure" boilers. In a "negative pressure" boiler, the air pressure inside the boiler's furnace area (where the combustion occurs) is below atmospheric air pressure. Thus, any leaks in the boiler furnace walls will tend to draw outside air into the boiler's furnace. With a "positive pressure" boiler, the air pressure inside the boiler's furnace is above atmospheric air pressure, and hence any leaks in the furnace walls will allow the gasses (and potentially ammonia if an SNCR system was installed) to leak out of the boiler and into the occupied areas of the building that encloses the boiler. Given the safety hazards associated with ammonia and that other NOx reduction options are available, SNCRs were not considered as viable alternatives for the Anclote Units.

Selective Catalytic Reduction

SCR is the most effective NOx reduction system. SCRs utilize catalysts (similar in concept to the catalytic converters used on modern automobile exhaust systems) and a reagent (ammonia) to reduce NOx emissions by approximately 90 percent. SCR systems, such as those proposed for the Crystal River units, have been retrofit on numerous generating units in the Ozone Transport Region, where Ozone Season NOx reductions have been required for the past several years. Air permits for new coal-fired units also generally require the installation of SCR systems. In addition to their NOx removal capabilities, SCR systems are also capable of transforming the mercury in the boiler's combustion gasses into a form that is more readily removable by an FGD system, another component of the overall CAIR/CAMR compliance plan at Crystal River.

An SCR consists of the "reactor", a large steel box-like structure that contains 2-4 layers of catalyst, and an ammonia injection grid (formed by a series of nozzles located just upstream of the reactor) for injecting vaporized ammonia. The reactor is located outside of the boiler. Combustion gasses are transported in ductwork from the boiler to the reactor, and then ducted back again to the boiler's air heater. This location is chosen because the temperature of the combustion gasses in this area of the boiler is generally in the operating temperature range of the SCR—approximately 630-750 degrees Fahrenheit. In most units, the temperature in the boiler at the point where the SCR is installed is within this temperature range at higher loads. But, as load decreases, so does the temperature. Systems that bypass combustion gasses from hotter areas of the boiler to the SCR are generally used to maintain the SCR's operating temperature at lower loads. However, in some instances, the minimum load that the unit can achieve is higher with the SCR in service than it would be without. This can impact system operations during extremely low load periods.

Due to their physical size and the constraints imposed for their location within the boiler's combustion gas stream, SCR designs are very unit specific. For example, for Crystal River Units 4 and 5, the space available to install the SCR reactors will allow for short runs of new ductwork, but must be built above existing structures, requiring a considerable amount of structural steel to support the reactor. For Crystal River Units 1 and 2, the space available for the reactors is extremely limited, and much longer runs of new ductwork will be needed in addition to the structural steel needed to elevate the reactor above existing structures. Also, Crystal River Unit 1 is adjacent to the Crystal River Unit 3 nuclear unit. Nuclear Security requirements may impede the ability to construct the SCR reactor in the most favorable location, and may necessitate additional measures to safely contain any ammonia produced for the SCR process.

For an SCR system, the ammonia can be supplied as liquid anhydrous ammonia (the most concentrated form), as aqueous ammonia (a dilute form of anhydrous ammonia that has fewer safety and handling concerns) or as either dry or liquid urea, with liquid urea available in several different concentrations. Compared to either form of ammonia, dry or liquid urea is safer to use, does not require formal Process Safety Management or Risk Management Plans, and does not require any special handling. In addition, at Crystal River, Nuclear Security and Control Room Habitability concerns would likely preclude the use and storage of large quantities of ammonia on the plant site. As for the choice between dry or liquid urea, liquid urea is generally less likely to be contaminated by impurities, and as dry urea needs to be dissolved in water to create a urea solution anyway, purchasing the urea in liquid form reduces the freshwater requirements that must be permitted by the local Water Management District. Dry urea also has the disadvantage of being extremely difficult to handle and transport if it absorbs moisture. This is of particular concern in the humid climate that exists at Crystal River. In either case, the urea is converted to ammonia in a conversion system and is then transported to the ammonia injection grid.

While SCRs have the advantage of being the most effective technology available to reduce NOx emissions from boilers, and have the added benefit of contributing to the ability of the FGD system to reduce the emissions of mercury, there are some disadvantages and concerns that must be taken into account.

As may be seen in Table 5-1, capital costs for SCRs are higher than for other technologies. Also, the catalysts used in the SCRs become contaminated over time, and less effective at reducing NOx emissions. After a 3-4 year period, additional catalyst must be added, then over future 3-4 year cycles, the catalyst must be either chemically "rejuvenated" or replaced. With the additional ductwork and the need for the combustion gasses to flow through the catalyst layers, SCRs require additional fan capacity to "force" the combustion gasses through the SCR. The other major cost component is the operating cost for reagents. It is worth noting that the reagent costs for the SCR systems are less than for SNCR systems. This is because the catalyst in the SCR promotes a more efficient reaction of ammonia with NOx, and so less ammonia is needed per ton of NOx removed.

Similar to SNCR systems, SCR systems are subject to ammonia slip and the resulting potential to cause fouling in the air heaters and contamination of the fly ash. This risk can be mitigated by proper design of the ammonia injection grid, computer modeling of the ductwork and reactors to design mixing devices to insure thorough mixing of the ammonia with the combustion gasses, and a control system that can react quickly and accurately to changes in conditions.

Another potential disadvantage of an SCR is that in addition to promoting the reaction of NOx with ammonia, the catalyst also promotes the formation of SO_3 from the SO_2 that is present in the combustion gasses. SO_3 can cause corrosion of the ductwork and components downstream of the SCR, and can cause a visible plume from the chimney. The amount of SO_3 formed by the SCR is dependent on the SO_2 levels in the combustion gasses (which in turn is dependent on the sulfur levels in the fuel being burned), and the composition of the catalyst materials. To control SO_3 emissions, catalyst materials with low SO_2 to SO_3 conversion rates can be specified during the design and procurement phase of an SCR project. Other technologies available to control SO_3 emissions include wet ESPs and systems that inject chemicals (such as ammonia or alkali sorbents) into the furnace. Chemical injection systems are generally considered to be the more cost effective choice, however as engineering of SCRs for Crystal River has not advanced to the point of determining the levels of SO_3 emissions that would be expected, no technology has been selected, and no costs included as yet, for SO_3 mitigation.

Summary of NOx Control Technology Options

The following table summarizes reduction capabilities and costs of potential NOx control technologies for PEF's Crystal River coal-fired units and Anclote Units 1 and 2.

Table 5-1. Summary of NOx Control Technology Options

	LNB	LNB/ CCOFA	LNB/ SOFA	LNB/ ROFA	LNB/ BOFA	SNCR	SCR
NOx Reduction %							
Crystal River 1	Installed	Installed	N/A	N/A	N/A	20	90
Crystal River 2	Installed	Installed	N/A	N/A	N/A	20	90
Crystal River 4	25	N/A	N/A	N/A	N/A	20	90
Crystal River 5	25	N/A	N/A	N/A	N/A	20	90
Anclote 1	N/A	27	38	32	20	N/A	90
Anclote 2	N/A	27	38	32	20	N/A	90
Capital Cost ($Millions)							
Crystal River 1	Installed	Installed	N/A	N/A	N/A	5.8	59.1
Crystal River 2	Installed	Installed	N/A	N/A	N/A	5.9	72.4
Crystal River 4	5.6	N/A	N/A	N/A	N/A	7.4	99.8
Crystal River 5	5.6	N/A	N/A	N/A	N/A	7.4	99.1
Anclote 1	N/A	2.3	5.0	12.5	4.3	N/A	69.0
Anclote 2	N/A	2.3	5.0	12.5	4.3	N/A	69.0
O&M Cost ($Millions/Yr, levelized, 2005$)							
Crystal River 1	Installed	Installed	N/A	N/A	N/A	0.2	0.7
Crystal River 2	Installed	Installed	N/A	N/A	N/A	0.2	0.8
Crystal River 4	0	N/A	N/A	N/A	N/A	0.2	1.1
Crystal River 5	0	N/A	N/A	N/A	N/A	0.2	1.1
Anclote 1	N/A	0.04	0.04	0.15	0.06	N/A	1.0
Anclote 2	N/A	0.03	0.03	0.15	0.06	N/A	0.9
Consumables Cost ($Millions/Yr, levelized, 2005$)							
Crystal River 1	Installed	Installed	N/A	N/A	N/A	1.3	0.7
Crystal River 2	Installed	Installed	N/A	N/A	N/A	1.5	0.9
Crystal River 4	0	N/A	N/A	N/A	N/A	3.2	1.1
Crystal River 5	0	N/A	N/A	N/A	N/A	3.1	1.1
Anclote 1	N/A	0	0	0	0	N/A	1.0
Anclote 2	N/A	0	0	0	0	N/A	0.9

Chapter 6 Overview of Mercury Reduction Technologies

Introduction

This chapter will provide information on the mercury (Hg) reduction technologies that have been considered for the PEF CAIR/CAMR Compliance Strategy. The chapter begins with background information on the formation of mercury and mercury reduction principles. It then discusses challenges associated with estimating mercury emissions and emission reductions. The chapter ends with a discussion of the estimated cost of mercury-specific reduction technologies.

Mercury Emission Formation and Mercury Reduction Principles

Mercury Speciation

Mercury (Hg) is a natural component of coal that is released to the flue gas during combustion. When the coal is burned in an electric utility boiler, the resulting high combustion temperatures vaporize the Hg in the coal to form gaseous elemental mercury (Hg^0). Subsequent cooling of the combustion gases and interaction of the gaseous Hg^0 with other combustion products result in a portion of the Hg being converted to gaseous oxidized forms of mercury (Hg^{++}) and particle-bound mercury (Hg^P).

The term speciation is used to denote the relative amounts of these three forms of Hg in the flue gas of the boiler. It is important to understand how Hg speciates in the boiler flue gas because the overall effectiveness of different control strategies for capturing Hg often depends on the concentrations of the different forms of Hg species present in the boiler flue gas.

In general, Hg speciation is dependent on:

- coal properties
- combustion conditions
- the flue gas composition
- fly ash properties
- the time/temperature profile between the boiler and air pollution control devices
- the flue gas cleaning methods, if any, in use.

The mechanisms by which Hg^0 is oxidized in flue gas are believed to include gas-phase reactions, fly ash or deposit-mediated reactions, and oxidation reactions in post-combustion NOx control systems. Data reveals that gas-phase oxidation is kinetically limited and occurs due to reactions of Hg with oxidizers such as Chlorine (Cl) and Cl_2. Research also suggests that gas-phase oxidation may be inhibited by the presence of NOx, SO_2, and water vapor.

Co-Benefit Approaches to Mercury Control

The capture of Hg by existing controls results from:

1. Adsorption of Hg onto fly ash with subsequent capture of Hg^P in a PM control device;
2. Adsorption of Hg by the alkaline sorbents used in dry scrubbers; or
3. The capture of Hg^{++} in wet scrubbers.

The key to capturing emissions is the chemical form of the mercury—elemental or ionic—as it passes through each pollution control device. Ionic mercury, which is soluble in water, is absorbed in scrubbers, whereas elemental mercury is not. Thus, the mercury-control challenge in a coal plant is primarily one of chemistry. For plants with existing or impending SO_2 controls, the objective is to increase the proportion of ionic mercury—either during combustion of the coal or in the flue gas itself—by some kind of oxidation process. Those without SO_2 controls may need to install mercury-specific technology.

The choice of what kind of controls to use is neither simple nor obvious. Chemistry and economics dictate that most coal plants will employ one mercury control approach rather than a combination, and the choice must be determined plant by plant because of the wide difference in coal plant designs, the pollution equipment they have, and the coal types they burn.

Mercury Removal in Particulate Matter (PM) Control Equipment

Gaseous mercury (both Hg^0 and Hg^{++}) can potentially be adsorbed on fly ash and be collected in a downstream ESP or FF. The modern ESPs and FFs that are now used on most coal-fired units achieve very high capture efficiencies for total PM. As a consequence, these PM control devices are also effective in capturing PM-bound mercury (Hg^P) in the boiler flue gases. All four Crystal River units utilize cold-side ESPs to capture particulate matter generated by the combustion of coal.

The degree to which mercury can be adsorbed onto fly ash for subsequent capture in PM control is dependent on the speciation of mercury, the flue gas concentration of fly ash, the properties of fly ash, the temperature of the flue gas in the PM control device, the amount of carbon in the ash, the concentration of SO_3, the Cl/SO_2 ratio, and the combustion process. It is currently believed that mercury is primarily adsorbed onto the unburned carbon in fly ash. Approximately 80 percent of the coal ash in pulverized coal (PC) fired boilers is entrained with the flue gas as fly ash. PC-fired boilers with LNBs have higher levels of carbon in the fly ash with a correspondingly higher potential for mercury adsorption.

Impacts of NOx Controls on Mercury Speciation and Capture

As discussed in Chapter 5, several NOx control technologies, including LNBs, OFA, SNCR, and SCR, are employed at utility coal-fired boilers to control NOx emissions. Of these control technologies, the SCR has an impact on the speciation of mercury in flue gas and, therefore, subsequent capture in wet FGD systems. Based on recent data, combustion controls such as LNBs and OFA, may also have the potential to increase mercury capture in fly ash.

Mercury Removal Though Combustion NOx Controls

The staged introduction of fuel and combustion air is a common practice for reducing formation of nitrogen oxides. This is often achieved within the burner in LNBs and also through the use of OFA when deeper staging and greater NOx reduction than afforded by LNBs alone is desired. Air staging reduces NOx formation by causing fuel-bound nitrogen to be released from the fuel at high-temperature and fuel-rich conditions. The fuel subsequently burns out under lower-temperature, oxygen-rich conditions to ensure high combustion efficiency with low NOx formation. Because all of the staged combustion methods used for minimizing NO_X formation result in delayed combustion when compared with combustion methods that do not try to minimize NO_X formation (and therefore burn the fuel only with maximum efficiency in mind), they also tend to reduce combustion efficiency and increase the amount of unburned fuel—in the form of unburned carbon, also known as LOI. The unburned carbon ends up in the fly ash that is collected in the PM control device. This carbon in the fly ash may act to adsorb Hg^0 and Hg^{++}. Therefore, existing combustion controls might be expected to enhance removal of mercury from the exhaust gases by downstream PM collection devices.

SCR Impact on Mercury Speciation

The speciation of mercury is known to have a significant impact on the ability of air pollution control equipment to capture it. In particular, the oxidized form of mercury, mercuric chloride ($HgCl_2$), is highly water-soluble and is, therefore, easier to capture in wet FGD systems than the elemental form of mercury which is not water-soluble. SCR catalysts can act to oxidize a significant portion of the elemental mercury, which makes it easier to remove in downstream wet FGD. The results of studies have suggested that oxidation of elemental mercury by SCR catalyst may be affected by the:

- space velocity of the catalyst
- temperature of the reaction
- concentration of ammonia
- age of the catalyst
- concentration of chlorine in the gas stream.

It is acknowledged that, at this point in time, the understanding of the effects of SCR catalyst on mercury oxidation is not complete. There is a great deal to learn with regard to the science of this phenomenon. However, apparently significant mercury oxidation by SCR catalyst occurs with bituminous coal, and oxidation is less certain with other coals.

Mercury Removal in SO_2 Control Equipment

As discussed in Chapter 4, both wet and dry FGD technologies are being used in the United States to control SO_2 emissions from coal-fired boilers. Available data reflects that some mercury capture occurs in both wet and dry FGD systems.

Mercury Removal in Wet FGD

Gaseous compounds of Hg^{++} are generally water-soluble and can absorb in the aqueous slurry of a wet FGD system. However, gaseous Hg^0 is insoluble in water and therefore does not absorb in such slurries. When gaseous compounds of Hg^{++} are absorbed in the liquid slurry of a wet FGD system, the dissolved species are believed to react with dissolved sulfides from the flue gas, such as hydrogen sulfide (H_2S), to form mercuric sulfide (HgS); the HgS precipitates from the liquid solution as sludge. In the absence of sufficient sulfides in the liquid solution, a competing reaction that reduces/converts dissolved Hg^{++} to Hg^0 is believed to take place. When this conversion takes place, the newly formed (insoluble) Hg^0 is transferred to the flue gas passing through the wet FGD system. The transferred Hg^0 increases the concentration of Hg^0 in the flue gas passing through the wet FGD (since the incoming Hg^0 is not absorbed), thereby resulting in a higher concentration of gaseous Hg^0 in the flue gas exiting the wet FGD compared to that entering. Transition metals in the slurry (originating from the flue gas) are believed to play an active role in the conversion reaction since they can act as catalysts and/or reactants for reducing oxidized species.

The capture of Hg in units equipped with wet FGD scrubbers is dependent on the relative amount of Hg^{++} in the inlet flue gas and on the PM control technology used.

Mercury Removal in Dry FGD

The performance of dry FGD systems in controlling SO_2 emissions is dependent on the difference between the SDA outlet temperature and the corresponding flue gas water vapor saturation temperature. Dry FGD systems on coal-fired boilers typically operate about 20 °F (11 °C) above the saturation temperature (i.e., an 11°C approach to saturation temperature). The relatively low flue gas temperatures afforded by dry FGD systems increase the potential for mercury capture. The caking, or buildup, of moist fly ash deposits, which can plug the SDA reactor and coat downstream surfaces, dictates the minimum flue gas temperatures which can be employed at the outlet of SDAs.

Hg^p is readily captured in dry FGD systems. Both Hg^0 and Hg^{++} can potentially be adsorbed on fly ash, calcium sulfite, or calcium sulfate particles in the SDA. They can also be adsorbed and captured as the flue gas passes through the ESP or FF, whichever is used for PM control. In addition, gaseous Hg^{++} may be absorbed in the slurry droplets and react with the calcium-based sorbents within the droplets. Nearly all of the Hg^p can be captured in the downstream PM control device. If the PM control device is a FF, there is the potential for additional capture of gaseous mercury as the flue gas passes through the bag filter cake composed of fly ash and dried slurry particles.

Mercury-Specific Control Options

Mercury can be captured and removed from a flue gas stream by injection of a sorbent into the exhaust stream with subsequent collection in PM control device such as an ESP or a FF. However, adsorptive capture of Hg from flue gas is a complex process that involves many variables. These include the temperature and composition of the flue gas, the concentration of Hg in the exhaust stream, the physical and chemical characteristics of the sorbent, the injection location, duct configuration, and injected PAC distribution in the flue gas. The implementation of an effective and efficient Hg control strategy using sorbent injection requires the development of low-cost and efficient Hg or multi-pollutant sorbents. Of the known Hg sorbents, activated carbons and calcium-based sorbents have been the most actively studied.

Today's leading mercury-specific approach, adapted from technology devised for solid waste incinerators, is the injection of fine powder sorbent material—typically activated carbon—into the flue gas flowing from the boiler. A sorbent works by attracting and binding mercury to its surface; the sorbent and mercury together are then captured by a downstream PM filter such as the ESPs fitted at most plants to control fly ash.

Currently, a significant amount of fly ash from coal plants is sold to cement makers for use as a concrete additive. This market benefits the environment by reducing CO_2 emissions from cement plants and minimizing landfill. However, conventional sorbents, which are captured along with fly ash, change the properties of the ash and render it unsuitable for use in concrete. This is important because all four Crystal River units sell their ash.

A potential solution to this problem is TOXECON. TOXECON works by delaying sorbent injection into flue gas until after the fly ash has been collected in a plant's primary particulate filter; the mercury-laden sorbent is then captured in a secondary filter, or baghouse, installed further downstream. In addition to preserving fly ash for concrete sales, this process requires less sorbent to achieve high levels of mercury capture because the sorbent has greater exposure to mercury in the ash-free gas stream.

New alternative sorbents are also being formulated that may not impact fly ash. However, these sorbents are still under development and are not available for commercial use today. These sorbents will likely be more expensive and perform at a reduced mercury removal rate.

Another mercury specific control technology utilizes fixed adsorption structures—plates or honeycombs coated with mercury sorbents such as gold or metallized solid polymer electrolytes that can collect much of the mercury remaining in flue gas after other treatments. This technology is still in the developmental stage.

Estimating Mercury Emissions and Reductions

Predicting mercury reduction and emissions is extremely challenging. There are many variables that are known to impact the mercury removal performance. Although a number of these variables have been identified, not all of their impacts to mercury removal performance are clearly understood. Chief among the uncertainties regarding mercury emissions is the amount of mercury in coal. The mercury content of coal varies widely between and within coal types. Coal samples were analyzed during the 1999 EPA information collection request. A total of 24,884 bituminous coal samples were analyzed with a mercury content range of 0.04 lbs/10^{12} Btu to 103.81 lbs/10^{12} Btu. Cambridge Energy Research Associates (CERA) lists the following mercury contents for various coal types.

Table 6-1. Mercury Content of Coal

Coal Type	Average Sulfur Content (lbs/mmBtu)	Average Mercury Content (lbs/Tbtu)
Northern Appalachian 4# SO_2	3.5	10.8
Northern Appalachian 6# SO_2	5.0	9.1
Northern Appalachian Other	2.5	10.6
Central Appalachian 1.2# SO_2	1.2	5.8
Central Appalachian 1.6# SO_2	1.8	7.8
Illinois Basin 2.5# SO_2	2.5	6.3
Illinois Basin 6# SO_2	6.0	6.3

Other elements and compounds in the coal impact the effectiveness of the mercury capture mechanism. Chlorine (Cl) and fluorine (F), both naturally occurring in coal, help to oxide elemental mercury to a form that is more readily captured. The sulfur content of the coal has tendency to slow this oxidation, therefore the ratio of chlorine to sulfur content in the coal is very important. For this analysis, the mercury, SO_2 and chlorine concentrations based upon CERA data, have been assumed. It must be recognized, however, mercury and chlorine levels are highly variable and deviations from the assumed mercury, chlorine and SO_2 concentration will directly impact the estimated mercury emissions.

Estimated Mercury Capture Performance

In addition to the variability of the fuel, a great deal of uncertainty exists with regard to the performance of the mercury control device. The mercury concentrations and mercury removal estimates assumed in PEF's analyses are based upon CERA and EPRI models and estimates. The mercury removal estimates are provided in Table 6-2, below. For all of the technologies, wide variations of actual mercury removal efficiency as compared to estimated mercury control efficiency may be experienced.

Table 6-2. Mercury Removal Efficiencies

	Coal Type		
Technology	Central Appalachian	Northern Appalachian	Illinois Basin
Cold-side ESP	39%	31%	39%
Cold-side ESP + SCR	44%	36%	44%
Cold-side ESP + FGD	66%	66%	69%
Cold-side ESP + SCR + FGD	80%	80%	80%
Cold-side ESP + PAC	75%	75%	75%
Cold-side ESP + Concrete-safe PAC	60%	60%	60%
Assumed Cl/SO_2 ratio	555	286	560

Estimated Mercury-Specific Control Costs

The following estimated costs are rough estimates only and are based upon EPA and EPRI published data, along with Progress Energy estimates. Actual costs for mercury control technologies will be site specific and are highly dependent upon the site configuration, available space, expandability of existing systems and escalation. These variables may result in wide variations of the actual mercury control costs as compared to estimated mercury control costs.

Powdered Activated Carbon (PAC) Injection

The capital cost includes the cost of the activated carbon material handling system, the injection system, controls, foundations, and installation are estimated to be $4 per kilowatt. Possible improvements to the ESP may be required to counteract the impact of the injected PAC which may increase costs by $6 per kW. Engineering and other indirect costs will add approximately $2 per kW, making the total cost approximately $12 per kW.

Operating and maintenance costs are broken down into three categories: sorbent costs, fixed costs, and sorbent disposal costs. Total O&M costs are estimated to be $0.70 per MWh.

TOXECON

The costs of two versions of the TOXECON technology were estimated. The first configuration utilizes a polishing fabric filter known as COPAC. The COPAC technology is a fabric filter following an ESP; since the particulate entering the fabric filter has already been reduced by the ESP, the filter size can be reduced. This results in higher air to cloth ratios in the fabric filter and bag life may be shortened. Currently air to cloth ratios are being developed that balance cost, performance and filter life. Any change in the design air to cloth ratio will impact the cost of the installed system.

The other configuration evaluated utilizes a pulse jet fabric filter (PJFF) in lieu of the COPAC system described above. The air-to-cloth ratios utilized in the PJFF are those proven in numerous applications. Utilization of these proven ratios results in a larger and more costly fabric filter.

The cost estimates for the Crystal River units are shown in Table 6-3.

Table 6-3. Estimated Costs of TOXECON Systems

($ Thousands)

	CR1		CR2		CR3		CR4	
Fabric Filter Type	COPAC	PJFF	COPAC	PJFF	COPAC	PJFF	COPAC	PJFF
Filter equipment cost	8,666	18,296	10,320	21,786	14,897	31,450	14,124	29,818
PAC Injection ($6/kw)	2,460	2,460	3,060	3,060	4,842	4,842	4,530	4,530
ID Fan, Motor, Electrical, Foundation and Ductwork	168	168	260	260	651	651	570	570
Indirect Costs	8,309	8,309	9,921	9,921	14,445	14,445	13,675	13,675
Total Cost	19,603	29,232	23,560	35,027	34,836	51,388	32,899	48,592

Operating and maintenance costs are broken down into three categories: sorbent costs, fixed costs, and sorbent disposal costs. Total O&M costs are estimated to be $0.70 per megawatt-hour (MWh) for the COPAC system and $1.20 per MWh for the PJFF system.

Because the COPAC system is estimated to be the lower cost system capable of achieving 75 percent removal efficiency, it is the system assumed to be installed in the analysis described in Chapter 12.

Concrete-safe Sorbents

The costs of sorbents that will not negatively impact the sale of combustion products (concrete safe sorbents) were estimated. Mercury control sorbents that do not impact the salability of fly ash are still in the development stage. The current assumption is that the sorbent costs will be twice that of the standard PAC and that removal efficiencies will be 20 percent less than standard PAC. Since these sorbents are still in the developmental phase, their performance and costs could vary greatly from those estimated here.

The capital costs associated with a concrete-safe sorbent system is estimated to be $12 per kilowatt, the same as the PAC injection system described above. The O&M costs for a concrete-safe sorbent system are estimated to be $0.90 per MWh, which includes a sorbent cost that is twice the cost of activated carbon.

Chapter 7 Overview of CAVR/BART Compliance Technologies

Introduction

This Chapter provides information on the technologies that have been considered for the PEF CAVR/BART Compliance Strategy.

Discussion

As described in Chapter 2, the BART requirements of CAVR potentially apply to the Crystal River Units 1 and 2 coal-fired units, the Anclote Unit 1 oil-fired unit, and the Bartow Unit 3 oil-fired unit. However, as Bartow Unit 3 will be repowered prior to the compliance date for the CAVR, currently expected to be in the 2013-2014 timeframe, no controls are being considered for Bartow Unit 3. Under EPA guidance, the presumptive BART limit for SO_2 emissions from coal-fired units such as Crystal River Units 1 and 2 is 95 percent removal, or 0.15 lbs SO_2/mmBtu. For the types of coal that would be burned at Crystal River, this would require a wet FGD system as more fully described in Chapter 4.

For NOx, the EPA guidance for tangential coal-fired boilers such as Crystal River Units 1 and 2 is 0.28 lbs NOx/mmBtu. This emissions rate would not likely require installation of an SCR system. However, the rate is lower than what might be expected to be achieved through the combustion staging technologies described in Chapter 5 without increasing the unburned carbon levels in the fly ash above levels that would allow continued sales of the ash. Although detailed studies of how to comply with this NOx limit have not been completed, it is likely that some form of SNCR system would be required. These more detailed studies would be need to determine the most cost effective method of compliance, considering the cost of the technology, the ongoing costs for any reagents (such as with an SNCR system), the expected value of NOx allowances (both annual and ozone season), any impacts on the continued sale of fly ash, the costs of disposal if the ash could not be sold, the level of mercury emissions that would be expected, and the value of mercury allowances—if there is a cap-and-trade system for mercury.

Because CAVR provides that compliance with CAIR can satisfy BART requirements, and the CAVR compliance date is several years into the future, PEF has elected not to incur additional costs at this time to develop a BART specific compliance study for Crystal River Units 1 and 2. Any such study would be initiated only if the Florida DEP ultimately determines that emission reductions from Crystal River Units 1 and 2 are needed to ensure compliance with CAVR.

For oil-fired units such as Anclote Unit 1, EPA guidance suggests that lower sulfur (1 percent) oil be burned to reduce SO_2 emissions, and that combustion modifications be utilized to reduce NOx emissions. Anclote has burned lower sulfur oils, with the cost of the oil (net of the value of SO_2 allowances) being the determining factor as to its use. As discussed in Chapter 5, combustion staging will reduce NOx emissions, but will generally increase unburned carbon in the fly ash in coal-fired boilers, and increase opacity and particulates in oil-fired boilers. As noted in Chapter 3, the potential increases in PM could require an NSR. This review could require the installation of PM controls such as an ESP. Again, as with the Crystal River units, further study would be needed to determine the optimal strategy at Anclote in the event DEP determines that additional reductions are needed to ensure compliance with CAVR.

Chapter 8 Fuel Supply Alternatives

Introduction

This chapter provides information regarding the existing fuel supply and transportation for PEF's Anclote, Suwannee River, and Crystal River plants. It also presents the fuel market assessments used in analyzing potential fuel supply alternatives to emission controls.

Overview of Fuel Facilities and Operational Considerations

Anclote

PEF's Anclote Units 1 and 2 have the ability to burn No. 6 fuel oil and natural gas. The Anclote plant receives No. 6 fuel oil via pipeline from the Bartow plant. Oil is delivered to the Bartow unloading facility via barge, normally from the ports of Houston or New Orleans. The Anclote plant has two storage tanks, with a total of 15.9 million gallons of storage at its site and has and an additional two storage tanks, with a total of 18.7 million gallons of storage at the Bartow unloading site. Anclote also may receive oil from the Bartow oil tanks in an emergency. Natural gas is transported to the Anclote plant via Florida Gas Transmission Company (FGT). Gas transportation capacity to the site is limited to approximately 50,000 mmBtu/day. No changes in fuel delivery are expected for the Anclote plant.

Suwannee River

The Suwannee River units have the ability to burn No. 6 fuel oil and natural gas. Oil is received via truck or CSX rail. Trucked oil generally comes via barge through St. Mark's terminal and from Jacksonville. Natural gas is received through Southern Natural Gas and South Georgia. No changes in fuel delivery are expected.

Crystal River

Crystal River Units 1, 2, 4 and 5 are coal-fired boilers. The Crystal River plant can receive coal via both rail and water. Historically, approximately 3.6 to 4.0 million tons of coal have been delivered via rail annually. Both compliance coal (1.2 lbs SO_2/mmBtu) for Units 4 and 5 and non-compliance coal (1.8 lbs SO_2/mmBtu) for Units 1 and 2 have been delivered by rail. Historically, approximately 2.0 to 2.4 million tons of coal have been delivered to Crystal River via barge. Compliance coal (Units 4 and 5) is the vast majority of coal shipped by barge, with only a few shipments of non-compliance coal in the past few years. Once on the plant site, coal is maintained in two separate coal yards. Coal is moved from the south coal yard to the north coal yard via an extensive conveyor system. Crystal River has the ability to blend coal at the IMT terminal near New Orleans, Louisiana. There is opportunity to blend on-site at Units 4 and 5, but it is a more limited option.

There is a possibility that one environmental control solution would be to install a scrubber at only one of the units at Crystal River Units 1 and 2. This would necessitate creating two separate coal piles to serve the two units in the south coal yard. The south coal yard not only stores the coal to Crystal River 1 and 2, it also is the unloading yard for all the barged coal. In order to retain the barge deliveries and maintain two separate coal piles, a significant coal yard re-design would need to be implemented, increasing complexity related to logistics and fuel handling. The use of two piles would also decrease reliability of the fuel supplies since the fuels would not be interchangeable between the units.

Fuel Market Assessment

Crystal River Coal

Supply Options Evaluated

The installation of scrubbers will allow for the testing and consumption of a much wider range of coals. The supply decisions are based on the performance of the fuels and the total costs of the fuel (fuel, re-agents, transportation, by-products, emission allowances, fuel handling, etc.). Crystal River has historically burned coal from Central Appalachia (CAPP) and South America. While the purchases have been both compliance (1.2 lbs SO_2/mmBtu) and non-compliance (1.8 lbs SO_2/mmBtu) coal, the sulfur content has been in a relatively narrow range. After the installation of scrubbers, PEF can meet its emission limits while using blends of coal that can include coals from Northern Appalachia (NAPP) or the Illinois Basin.

Due to economic uncertainty inherently present in any price forecast, the first priority in defining long-term coal sourcing options supporting scrubber design criteria is flexibility. Because of this, it is extremely important to identify design limitations that provide an optimized balance between maximum fuel sourcing flexibility and economic prudence.

Current forecasts for several fuel types were incorporated into the option screening model (discussed in Chapter 11) and analyses were completed for various sulfur content blends. The outcome from this analysis showed that the most economical approach is to use higher sulfur coal when scrubbers are installed. Therefore, the upper design basis for Crystal River units 4 and 5 is set at 6.0 lbs SO_2/mmBtu. Since the limit is established at this upper band, procurement flexibility can be maximized and expanded into all bituminous coal regions thereby affording us the ability to take full advantage of attractive pricing options by region.

The analysis includes rail and water transportation alternatives. In the 6.0 lbs SO_2/mmBtu option, sourcing is a blend of a high sulfur (6.0 lbs SO_2/mmBtu) Ohio River product delivered via barge and a high sulfur (4.0 lbs SO_2/mmBtu) NAPP product delivered via rail. This was considered to be the most conservative economic comparison, as higher sulfur fuel options become available closer to the Crystal River facility they decrease in overall delivered price offering increased comparable savings. With the exception of 500,000 tons per year earmarked for delivery of import coal, the approach is to maximize water-borne deliveries from a high sulfur region first and then supplement remaining supply needs with high sulfur rail deliveries via CSX. This method provides a total of 2.7 million tons of available delivery supply via water and the remaining 3.3 million tons to be delivered via rail regardless of the sourcing regions chosen.

NAPP coals have not been tested at Crystal River. In addition to higher sulfur content, these coals generally have lower fusion temperatures, which can cause slagging in the boiler. Rail is the only logistical and economical alternative for these coals to access Crystal River. NAPP coals sell at a discount to CAPP coals and their production is on the rise. Utilities want to access these reserves, but the rail companies have indicated that they do not expect to expand the infrastructure necessary to make these reserves readily available. Additionally, they have generally raised their prices so that they, and not the utilities, capture the reward of the producer's lower prices. This pricing may cause utilities that are closer to NAPP to have a geographic advantage over others. In the event NAPP coals cannot be economically secured, PEF would use CAPP coals of similar quality in the fuel blend.

Illinois Basin coals have the highest sulfur contents and lowest fusion temperatures of the coals considered for Crystal River. Although the use of Illinois Basin coal was contemplated in the design of the Crystal River Units 4 and 5 boilers, these coals are untested at Crystal River. These reserves are relatively untapped due to the lower quality and more greatly discounted than other coals. Economically, these coals would travel to New Orleans via river barge, then ocean barge to Crystal River. Multiple railroads would be necessary to move the coal via rail and the deliveries would meet significant congestion moving both east and south. Barge companies have not raised their rates to capture the margins, as the railroads have. As such, it is expected that Illinois Basin coals would be a portion of the blended coals at Crystal River.

Crystal River must have coal delivered by rail to meet its full burn requirements and CAPP is a likely region for rail coal purchases. CAPP coal can also be moved via river barge to New Orleans and cross-Gulf to Crystal River. CAPP coals have been widely tested and procured for Crystal River and a wider range of qualities will be able to be used. CAPP reserves are on decline, but higher prices and the opening of lower quality reserves may slow the decline.

Foreign coal will come in via barge to Crystal River. These coals have been successfully tested and procured for Crystal River. This quality of coal is not required with the implementation of scrubbers, but it can be competitive under certain scenarios. The producers have invested much to develop the US market and they may set their market prices at the level that they clear the US market, regardless of its higher quality. Lower transportation rates compared to other markets or lower international water rates, compared to domestic water or rail rates may also allow this product to compete with the domestic coals.

Market Outlook

In general, coal prices are at higher levels due to declining CAPP reserves, railroad constraints across the US, low inventory levels at many U.S. utilities, and competition for foreign coal. Coal prices are expected to moderate as scrubbers are installed and utilities can access a wider range of reserves.

Transportation Outlook

Rail service is provided by CSX and the short-line railroad, Florida Northern. [redacted]

Barge service is provided by several companies under contracts awarded through a competitive bidding process. Due to the dimensions of the channel and turning basin, there are a limited number of barges that can navigate the Crystal River canal. [redacted] 1 2

Anclote and Suwannee River Oil

Supply Options Evaluated

Different grades of No. 6 oil can be utilized at Anclote. These grades are commingled at the site and burned in both units. The two units can be aligned with each of the two oil tanks to run different grades of oil. However, the logistics to coordinate the delivery of specific barges and pipeline shipments to specific tanks are complex. Additionally, reliability is greatly reduced by eliminating the ability to use all infrastructure resources to commit to either unit. The overall management of emissions can be achieved more efficiently and reliably through a commingled oil supply, rather than two distinct oil supplies. Decisions related to supply are based on the cost of the oil by sulfur content, the cost of the related emission allowances, and the cost and availability of natural gas.

The Suwannee River plant has switched between No. 6 fuel oil and natural gas during the summers. Peaker Unit 1 at Suwannee River requires equipment change-outs each season to burn natural gas and then return to oil in the winter. Supply decisions are based on the cost of the oil by sulfur content, the cost of the related emission allowances, and the cost and availability of natural gas.

Market Outlook

Strong demand in the 2002 to 2004 period eliminated all the cushions in the industry. Oil market demand remains bullish for the near-term future, with growth dominated by China and India. On the supply side with US production flat to declining, the oil market is highly dependent on imports and OPEC's spare capacity has been limited. The major exporters are developing countries, which lack strong democratic institutions and are vulnerable to instability.

Transportation Outlook

The Anclote plant receives its oil via barge service from Rio Energy. The Suwannee River plant receives its oil by truck and railcar. Transportation is readily available to both plants, subject to weather delays. [redacted] 3 4

Anclote and Suwannee River Natural Gas

Supply Options Evaluated

Natural gas supply is available at Mobile Bay and, in the future, will be available from the Elba Island LNG facility for Anclote. For the Suwannee River plant, gas is available from onshore and offshore sources and will include Elba Island LNG in the future. Due to the infrequent use of natural gas for economic reasons, supply is secured under short term transactions.

Market Outlook

Increased demand, conventional production declines, and supply shortfalls due to hurricanes in the Gulf of Mexico have placed upward pressure on prices in the short-term. Restoration of production after the hurricanes and mild weather, should moderate natural gas prices from their 2005/2006 winter highs. However longer term prices would trend down as the LNG imports increase in 2009 but will remain high enough to attract LNG to the United States.

Transportation Outlook

Deliveries to Anclote and Suwannee River are made utilizing interruptible transportation service, released firm service or firm service directed from other PEF plants, but the units do not have dedicated firm service since it is not cost effective at the expected gas volume levels. Transportation on Southern Natural Gas has been approximately $0.35/mmBtu on a reservation basis, plus variable costs. The firm transportation price from the FGT western system is approximately $0.78/mmBtu paid on a reservation basis, plus variable costs.

Data Quality and Sources

Coal – Global Energy Forecasting Methodology

Progress Energy develops its delivered coal price forecasts based on information from Global Energy Decisions (Global Energy). Global Energy uses an integrated fuel forecasting approach based upon a stochastic data model, fundamental modeling solutions, and market expertise to provide analysis of fuel supply and demand fundamentals, expected prices and how they are formed.

Coal price forecasts are based on short-term and long-term models. Because coal prices respond to model inputs differently over time, Global Energy utilizes an econometrically based short-term model and a supply-and-demand based long-term model. In both models, the output is intrinsically linked to price forecasts for competitive fuel, such as natural gas, ensuring the competitive interplay between coal and natural gas prices remains intact.

For forecast periods of five years or less, short-term coal prices are heavily dependent on marketplace fluctuations such as:

- Weather
- Coal stockpile volumes
- Short-term natural gas forecasts
- Short-term SO_2 allowance price forecasts
- Recently signed coal contract data
- Known transportation constraints
- Known supply constraints
- Known competitive fuel constraints
- Inter- and intra-fuel competition

In the short-term, factors such as new plant development, technology advancements, and reserve conditions do not significantly influence prices because these factors often require five years or more before the effects are felt. Temperature differences will drive coal prices up or down, depending on the season. The size of coal stockpiles will influence coal prices as utilities replenish their stocks. Short-term forecasts of natural gas will typically set a ceiling on coal prices. Emission allowance price forecasts will influence coal-on-coal competition. Recently signed contracts will also influence the short-term coal market as they give an indication of how the market prices the future value of coal.

Long-term coal price forecasting is dependent on:

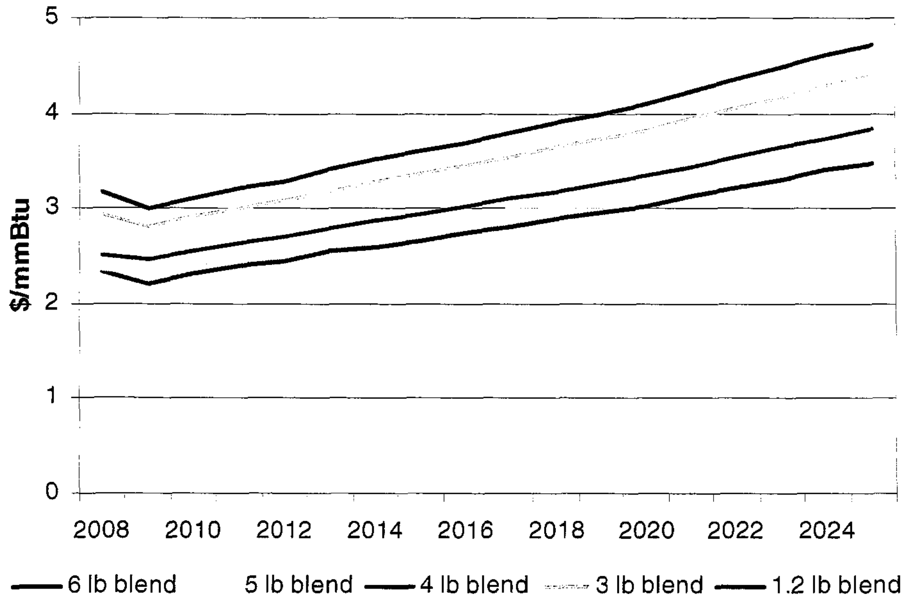
- Reserve conditions
- Reserve accessibility
- Transportation trends
- Development of enhanced coal technologies
- Future air emission regulations
- New emission control construction
- Long-term SO_2 allowance price forecasts
- New plant development
- Inter- and intra-fuel competition

The dominant long-term factors tend to be reserve conditions, reserve accessibility, transportation constraints, technology advances, and the price of competing coal and gas. Reserve conditions are used to determine extraction costs of the coal. Reserve accessibility and transportation constraints will help determine the amount of coal available to the market. Technology advances will impact future extraction and transportation costs.

Beyond the dominant long-term factors, future air emissions will impact SO_2 allowance price forecasts. Additionally, CAIR and CAMR will impact the combustion of coal in the eastern 28 states. The scheduled construction of 50,000 MW of emissions control devices will likely decrease the demand for low sulfur coal products. With 68,000 MW of new coal burning power plants proposed to be constructed over the next decade, the impact on coal demand as well as applicable coal markets will be significant. The final location of these plants will affect transportation capacity and coal prices.

The forecasts of delivered coal prices used in the analyses described in Chapters 11 and 12 are shown in Figure 8-1. The figure shows the prices for various blends of coal, based on the pounds of SO_2 /mmBtu produced by burning the various coals.

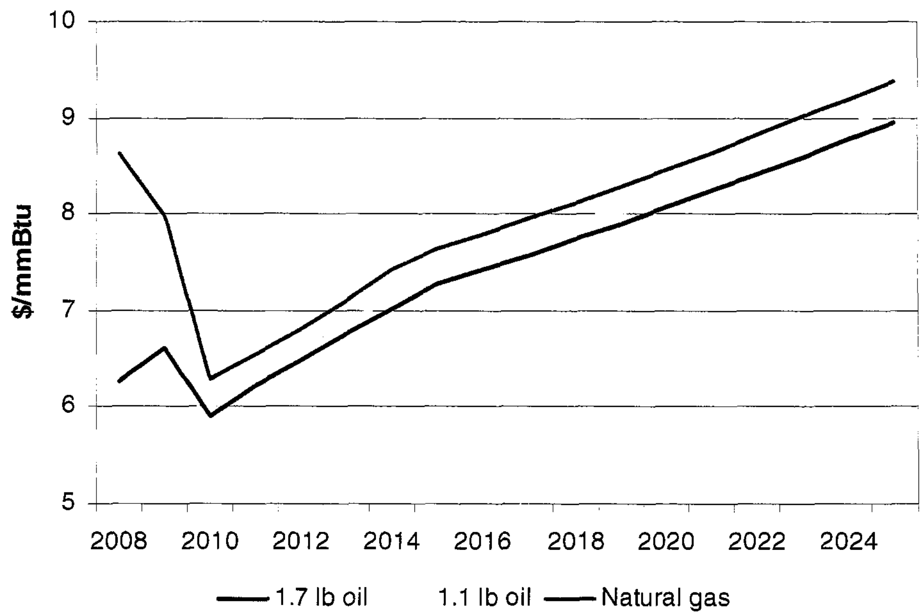
Figure 8-1. Delivered Coal Price Forecasts



Gas and Oil – Progress Energy Forward Curve Methodology

Progress Energy develops its natural gas forward curves based on NYMEX forward curves for the first two years and forecasts from PIRA for the remainder of the period, adjusted for the price differential between the Henry Hub and the supply points where PEF purchases its gas and PEF's market view. The delivered oil and gas price forecasts used in the analyses described in Chapters 11 and 12 are shown in Figure 8-2.

Figure 8-2. Oil and Natural Gas Price Forecasts



Chapter 9 Emission Allowance Markets

Introduction

This chapter addresses how emissions are traded, recent price activity and forecasts for prices looking forward. The extreme volatility in emissions is also addressed, as well as the drivers behind this volatility. The drivers for emissions prices are diverse and include weather, fuel prices and government regulations.

Trading of Allowances

Allowances are traded in the open market between various counterparties. The allowance trading market is not considered "liquid" meaning that allowances cannot be bought and sold as readily available products such as natural gas and fuel oil. As a result, deals can take several days or weeks to obtain commitments from both counterparties. Once the parties reach agreement, a bilateral contract is prepared and exchanged with the counterparties for review and comments. Adding to the complexity of the transaction, each allowance is unique, identified by a serial number and vintage year in a company's EPA Account, and unused allowances may be used in future years.

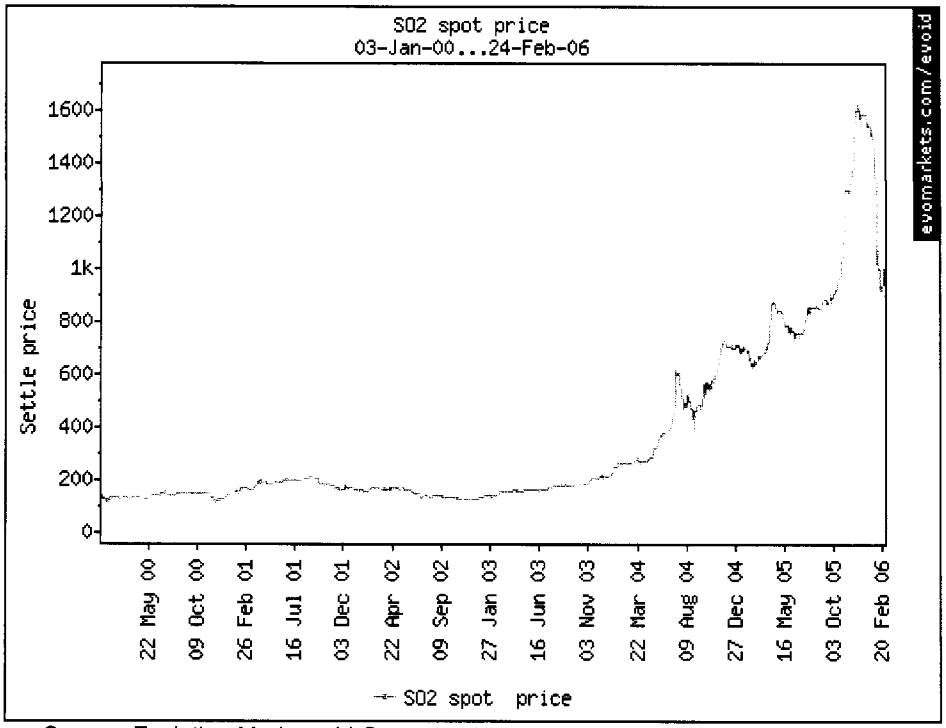
SO_2

Historical and Forecasted SO_2 Allowance Market Outlook

Allowance prices, particularly SO_2, have experienced tremendous volatility in recent history. The SO_2 market, which for the first three of the past five years traded around $200/ton, reached prices *eight times* this level at the end of 2005. Figure 9-1 shows SO_2 allowance prices from January 2000 through February 2006.

Some of the increases experienced last year were attributed to the year-end assessment of emitting companies' 2005 SO_2 positions. According to industry expert JD Energy, the high prices also were associated with light trading of allowances – emphasizing the consequences of an illiquid commodity when demand (or perceived demand) increases. The market for SO_2 allowances also reacted with higher prices after the EPA formally adopted CAIR in March 2005, because the rule solidified some of the speculation that more allowances would be required for each ton of SO_2 emitted in future years. A final driver to the increase in allowance prices was the run-up in natural gas prices after Hurricanes Katrina and Rita.

Figure 9-1. Historical SO_2 Allowance Pricing

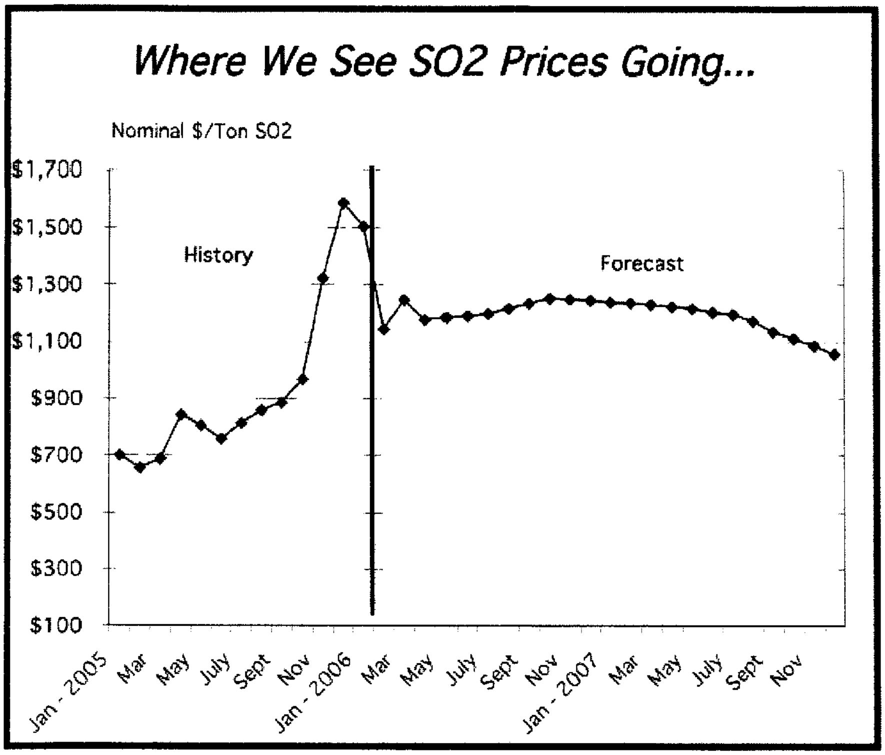


Source: Evolution Markets, LLC

Very recently, there was a rapid increase in SO_2 prices from just over $900/ton at the beginning of October 2005 to $1,600/ton at the end of 2005, followed by a sharp reversal to $1,100/ton in the beginning of February 2006. The $1,600/ton range was sustained for under a month, and as of early February prices have quickly tumbled to $1,100/ton. Fundamentally, it is possible this decline can be partially attributed to natural gas prices, which have fallen and are presently near their pre-hurricane levels. However, the decline again highlights the vulnerability of this thinly traded market – one with a very limited number of trading parties. The fall was quick, and some market observers point to just two recent events that may have been responsible. The first is a comment made in a speech by an EPA official indicating that allowances (at the $1,600/ton level) were overvalued and the more appropriate estimates by the EPA were in the $1,000 to $1,200 range. The other event was the sale of a fairly large number of allowances by a single participant, which ignited some panic selling by the market.

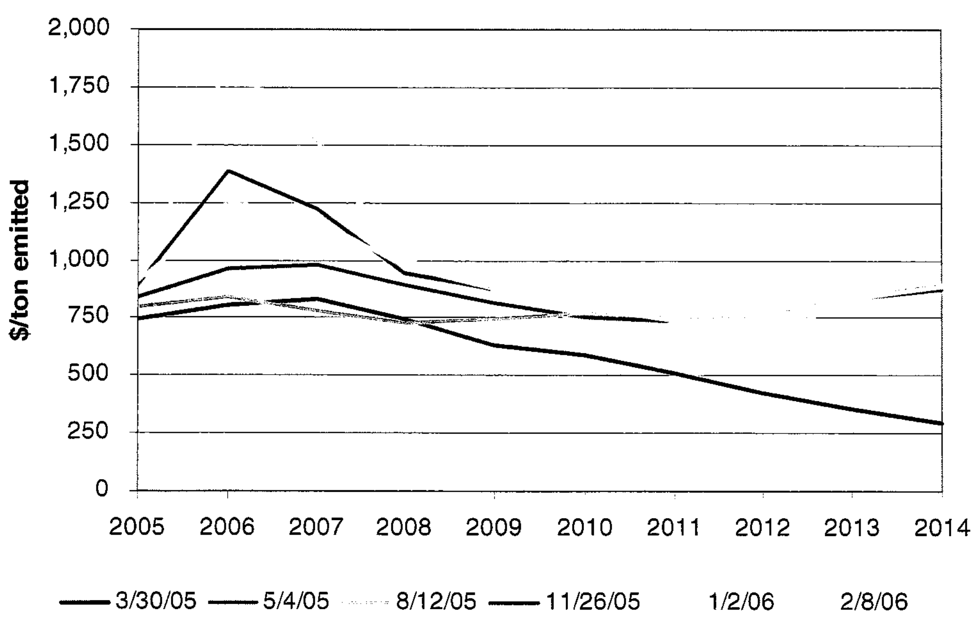
PEF believes SO_2 allowance pricing will remain a function of supply versus demand and will continue to see great volatility. Below, in Figure 9-2, is JD Energy's most current update of SO_2 prices. The jump, followed by the decline, between historical prices and current forecasts is quite sharp and came as a reaction to the recent decrease in prices as well as the change in the factors that influence pricing. The dynamic nature of these forecasts is better seen in Figure 9-3, which shows how forecasts from the same source have changed over a short period of time.

Figure 9-2. JD Energy's Near-Term SO_2 Allowance Price Forecast



Source: JD Energy, Feb. 8, 2006

Figure 9-3. JD Energy's SO_2 Allowance Price Forecasts Over Time

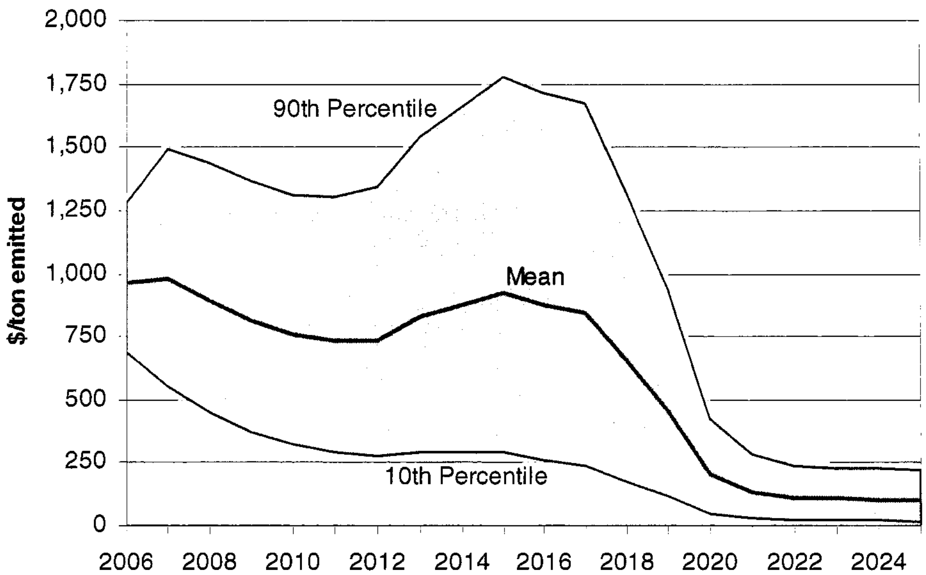


Source: JD Energy

Figure 9-4 is an earlier forecast of JD Energy's long-term base case SO_2 prices. This figure clearly demonstrates, based on probabilistic modeling, how wide the range of possible prices was at the time the forecast was generated. The gray area is intended to show, with 80 percent confidence, where prices should be in each year. The volatility of these prices is clearly demonstrated by the fact that prices in 2005 and 2006 exceeded the 90th percentile high-price case. The price projections shown in Figure 9-4 are used in the economic analyses discussed in Chapter 12.

With no end in sight expected for uncertainty in the market, uncertainty in control technology costs, and regulatory uncertainty, PEF cannot depend on the SO_2 allowance market for a substantial portion of its CAIR compliance strategy, especially in the early years of compliance (i.e., 2010-2014).

Figure 9-4. Distribution Around JD Energy's Long-Term SO_2 Allowance Price Forecast



Source: JD Energy

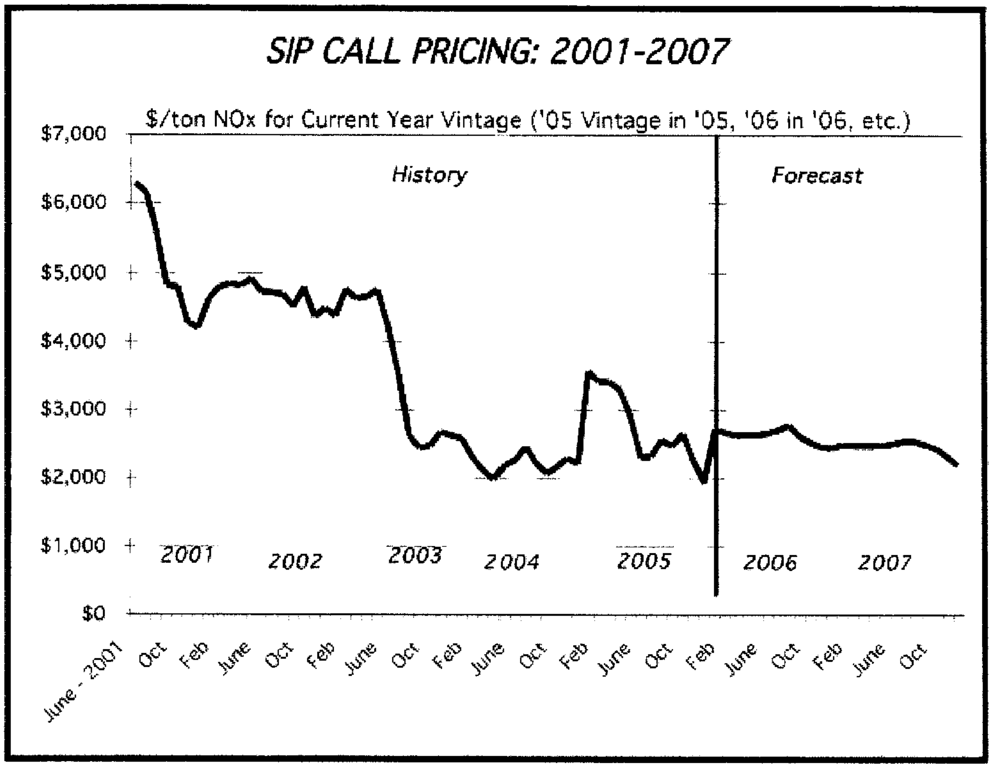
NO_X

Historical and Forecasted NOx Allowance Market Outlook:

Historically, NOx allowances have only been traded in states that are subject to EPA's NOx State Implementation Plan (SIP) Call Rules and Regulations. Florida is not one of those states. As explained in Chapter 2, however, CAIR encourages Florida to implement NOx cap-and-trade allowance programs to achieve annual and ozone season emission budgets. The details of each state's implementation plan for a program that includes both ozone season and annual NO_X trading is due by September of 2006.

The following charts show, for different periods of time, the historical spot price of NOx allowances. Figure 9-5 below reflects historical NOx allowance pricing since January 2001 as well as forecasted prices through 2007.

Figure 9-5. JD Energy Historical and Near-Term Forecast NOx Allowance Prices



Source: JD Energy, Feb. 8, 2006

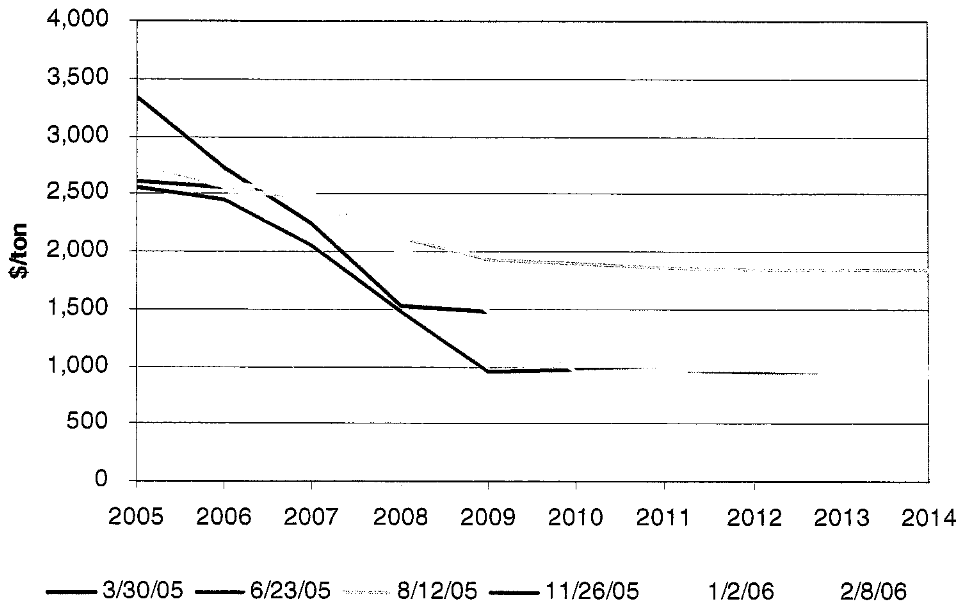
NOx allowance prices have seen dramatic changes over the past five years, as shown in Figure 9-5. As an immature market, and supported by extreme spikes in gas and oil prices, NOx allowances traded near $5,000/ton in 2001 and 2002. As more players slowly entered the market and with lower fuel costs and better information regarding the costs of control technologies, prices fell to $2,000/ton in 2003. Over the course of 2004 and 2005, prices gained new ground, at times passing the $3,000/ton mark.

Currently, prices have retreated somewhat and are back near the $2,700/ton mark. The up and down price movements at the end of 2005 can be attributed to the completion of the ozone season (September 30th) and the fact that companies must be in compliance with the EPA by November 30th of each year. As actual NOx emissions were reported, companies may have been faced with shortages of NOx allowances, forcing them into the market to purchase additional allowances to be in compliance. Following NOx compliance activities, prices once again fell due to the belief by many market participants that the carryover from 2005 will be substantial and there will be a surplus of NOx allowances over the next few years.

The forecast from JD Energy in Figure 9-5 shows NOx allowance prices staying in the mid $2,000/ton range through 2007. The most recent forecast from JD Energy, as shown in Figure 9-6 below, shows the forecast declining after 2007 and eventually reaching $1,000/ton in 2010. This decline is attributed to a substantial bank of surplus allowances and the elimination of Progressive Flow Control under CAIR in 2009, as well as improvements in NOx reduction technologies starting in 2010. PEF believes that JD Energy's forecast represents, from a fundamental standpoint, the optimal and most likely scenario of where NOx allowance prices will be if NOx controls are installed as currently forecasted. However, the enormous range that prices have seen over the past few years clearly demonstrates that prices are extremely volatile and the range of possibilities is very wide.

As demonstrated in Figure 9-6, the forecasts for NOx allowance prices have been dynamic over the past year. This figure shows how forecasts from the same source have changed over a short period of time with changes to the underlying fundamental market assumptions, with some influence from observable market pricing at the time of the forecast.

Figure 9-6. JD Energy's NOx Allowance Price Forecasts Over Time

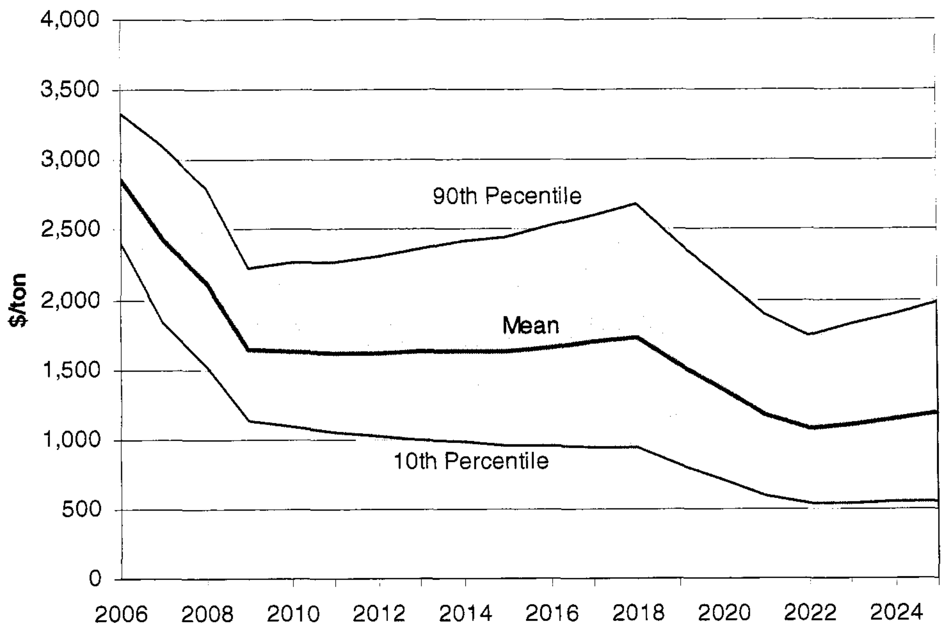


Source: JD Energy

Figure 9-7 is an earlier forecast of JD Energy's long-term base case NOx prices, in addition to the range of possible prices implied by this forecast and implied market volatility. This forecast was used for in the evaluation described in this document. This figure clearly demonstrates, based on probabilistic modeling, how wide the range of possible prices reached at the time this forecast was generated. The gray area is intended to show, with 80 percent confidence, where prices should be in each year. The price projections shown in Figure 9-7 are used in the economic analyses discussed in Chapter 12.

While the difficulties associated with forecasting NO_X prices have been illustrated, in 2009 these markets will see increased complexity and uncertainty with the introduction of annual NO_X trading in addition to trading for the ozone season. Details and allocations are still being worked through as part of the SIP (State Implementation Plan) that is due in September, 2006; but the essence of what is required by CAIR is a distinct market and distinct allowances for annual compliance and ozone season compliance. Market forecasters are unsure how each will be valued, and whether or not there will be a premium market. For the analyses presented in this report, PEF has assumed NOx allowances in both markets will be priced the same.

Figure 9-7. Distribution Around JD Energy's Long-Term NOx Allowance Price Forecast



Source: JD Energy

Conclusion

The costs of SO_2 and NOx allowances have seen tremendous swings since the beginning of this decade. The illiquidity of the market exacerbates this problem, leaving it vulnerable to continued volatility. Even experts in price forecasting have had a difficult time anticipating future prices and have been forced to change their outlook with changes in the underlying price drivers. PEF believes that forecasting allowance prices will continue to be challenging, and the markets will continue to experience great volatility.

Chapter 10 Other Compliance Alternatives

Introduction

The purpose of this chapter is to describe other compliance alternatives that were evaluated. These alternatives include generating system changes that could be made for environmental compliance that are separate and distinct from potential scrubbing and fuel switching strategies discussed in other chapters.

Environmental Dispatch

One method for meeting a limit on SO_2, NOx, and mercury emissions is to operate units with lower emission rates more than units with higher emission rates. The strategy has the most potential for reducing emissions when there are other low-emitting units that would not otherwise be expected to be utilized to their full extent. In the case of PEF, the natural gas-fired combined cycle units represent the only opportunity to reduce emissions using environmental dispatch. This option, however, is very expensive given the forecast of natural gas prices.

A simple example will demonstrate that environmental dispatch, sometimes referred to as compliance dispatch, is not a cost-effective long-term solution for PEF. Crystal River Units 1 and 2 currently have the highest emission rates of the Company's coal units, producing roughly 9.2 tons of SO_2 /GWh of generation with a projected average fuel cost of $30.4/MWh in 2010. Assuming their generation is replaced by generation from combined cycle units with an average heat rate of 7,580 Btu/kWh and a natural gas price of $6.91/mmBtu in 2010, the additional fuel cost of the generation from the combined cycle unit is roughly $22,000 per gigawatt-hour. Therefore, the cost of SO_2 removal in 2010 is approximately $2,400 per ton of SO_2 removed. Over the 2010-2034 time period, the levelized cost of removal is around $2,225 per ton (in 2005 dollars). As will be shown in Chapter 11, this is significantly greater than the incremental cost to scrub Crystal River Units 1 and 2. It is also greater than the forecasted cost of SO_2 allowances.

A similar type of analysis could be performed to compare the cost of environmental dispatch to NOx control costs. However, if environmental dispatch is being performed for SO_2 control (that is, replacing coal-fired generation with combined cycle generation), then the NOx emission reductions are obtained at no additional cost. Therefore, a simplified analysis was performed of the total cost of installing SO_2 and NOx controls (wet scrubbers and SCRs on Crystal River Units 1 and 2) compared to replacing the generation with the equivalent amount of energy from combined cycle plants. In this hypothetical case, the SO_2 and NOx reductions would be greater for the environmental dispatch case than could be achieved by installing scrubbers and SCRs on Crystal River Units 1 and 2; therefore, allowances were assumed to be purchased to make up the difference in reductions. The analysis showed that environmental dispatch would cost an extra $35 million per year (levelized 2005 dollars) more than installing scrubbers and SCRs on Crystal River Units 1 and 2.

While environmental dispatch is not cost-effective as a long-term compliance measure, it does provide the Company with operational flexibility as a short-term emission reduction tool, if needed.

Repowering

In mid-2005, PEF analyzed the economics of repowering the Bartow oil-fired steam units to gas-fired combined cycle units and found the benefits to exceed the costs. In addition to the benefits associated with increased generating capacity, there were benefits associated with reductions in SO_2 and NOx emissions, as well as other benefits.

The Company's Anclote and Suwannee River units are also oil-fired steam units. These units are not being considered for repowering at this time for a couple of reasons. First, the Anclote and Suwannee River units are currently projected to operate at average capacity factors in the 20 – 25 percent range. Thus, repowering these units will provide little emission reductions since the units are not projected to run very much (each Anclote unit emits approximately 7 percent of the Company's total SO_2 emissions and 3.5 percent of the NOx emissions, and the Suwannee River units less than one percent). Second, repowering the units will increase the Company's reliance on natural gas at a time when the Company and the Florida Public Service Commission are seeking fuel diversity. Even though PEF and the Commission desire fuel diversity, the option to repower Anclote and Suwannee River and burn gas at the units must be maintained, should emission restrictions, or other conditions, change in the future. Since these units can burn some amount of natural gas as steam units, PEF can obtain some of the emission reduction benefits of burning natural gas without having to spend additional capital.

Retirement of Existing Coal Units

The installation of scrubbers and selective catalytic reduction facilities on the Crystal River coal units requires significant capital expenditures. Therefore, the cost of installing scrubbers and SCRs was compared to the cost of building a new coal-fired plant. A new coal unit of the size of a combined unit 1 and 2 would be around 860 MW. At an estimated capital cost of $1,325 per kW, an 860 MW coal unit would have total capital requirements of $1.14 billion (2005 dollars). The estimated total capital requirement for the scrubbers and SCRs for Crystal River 1 and 2 is $494 million, or less than one-half the cost of building a new unit to replace Crystal River Units 1 & 2.

This simple analysis of capital requirements demonstrates that retiring Crystal River Units 1 & 2 and replacing them with new coal-fired capacity is not a cost-effective alternative. In addition, since the environmental controls on a new coal unit are essentially the same as are being considered for Crystal River Units 1 and 2, there would be no significant net reduction in emissions by retiring Crystal River Units 1 and 2 and building a new coal unit.

Chapter 11 Economic Screening of Compliance Options

Introduction

This chapter presents the economic screening analysis of the Company's compliance options—primarily the options available to reduce SO_2 and NOx emissions. The objective of the screening analysis was to eliminate the compliance options that were not economic, preserving only the options that merit further consideration in developing the Company's compliance plan. Some compliance options, such as retiring or repowering existing units, are not part of the economic screening described in this chapter. These alternatives are described in Chapter 10.

As described in Chapters 4 and 5, some screening of SO_2 control and NOx control technologies was completed prior to the economic screening described in this chapter. Chapters 4 and 5 provide detailed information on SO_2 and NOx control technologies. Table 11-1 lists the SO_2 and NOx control options evaluated in the economic screening.

Table 11-1. Options Considered for Screening

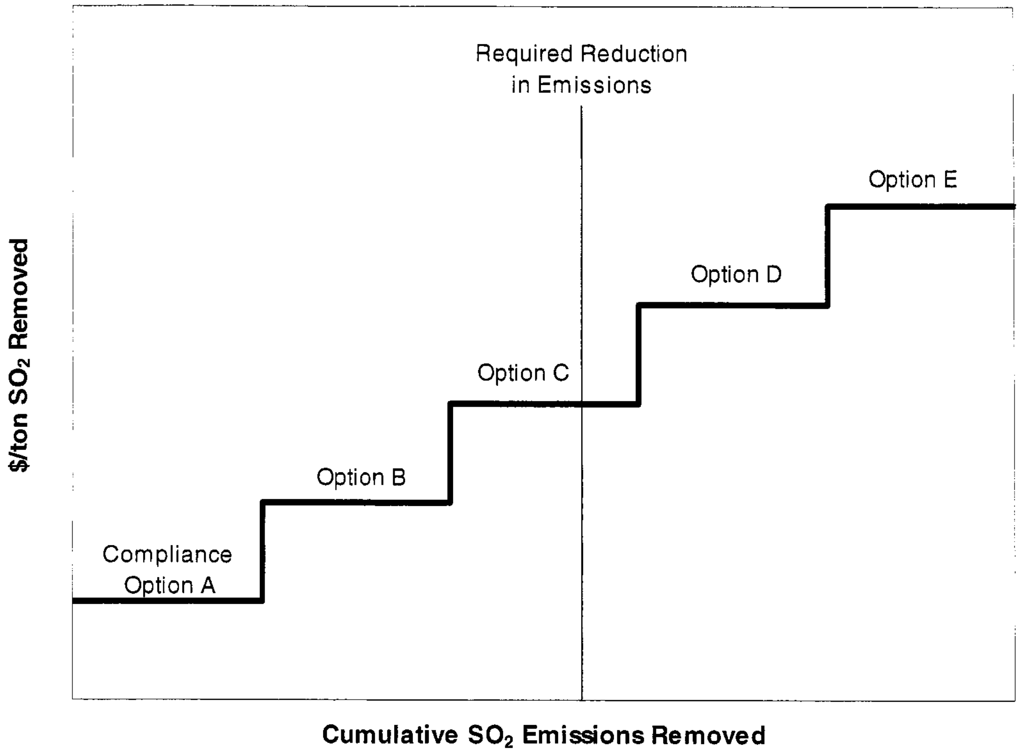
SO_2 Control Options	NOx Control Options
Central Appalachian Compliance Coal	Natural gas Co-burning with Residual Oil
Low Sulfur (1.1 lb) Residual Oil	Partial-year Natural Gas use
Natural gas Co-burning with Residual Oil	Low NOx Burners (LNB)
Partial-year Natural Gas use	Over-fire Air Systems (BOFA, CCOFA, ROFA, SOFA)
Dry Scrubbers (with 3 lb coal)	Selective Non-Catalytic Reduction (SNCR)
Dry Scrubbers (with 1.8 lb coal)	Selective Catalytic Reduction (SCR)
Wet Scrubbers (with 5 lb coal)	
Wet Scrubbers (with 4 lb coal)	

Overview of Screening Process

The criterion used for screening was relative cost effectiveness as measured by the incremental cost per ton of pollutant (SO_2 or NOx) removed. The incremental cost per ton removed is a measure of the cost to remove the next ton of pollutant. It is the appropriate criteria for selecting the most cost-effective compliance plan when system (versus unit specific) emissions must be controlled, as is the case with reductions under CAIR.

One reason that the incremental cost of control is the relevant measure is utilities can purchase emission allowances in order to comply. This implies a utility should compare its internal cost of controlling emissions to the cost of purchasing allowances. Based on solely economic criteria, a utility would implement all internal compliance measures from least cost to highest cost up to the cost of buying allowances (i.e., the dollar per SO_2 allowance price is lower than the incremental cost to reduce the next ton of SO_2). This "threshold" value can not be determined unless incremental cost analysis is performed. Figure 11-1 illustrates this process graphically.

Figure 11-1. Illustration of Incremental Cost Supply Curve



The incremental cost of control also measures the "bang for the buck;" that is, the additional amount of reduction received for the additional cost. Just as incremental $/MWh is used in dispatch of generating units to determine the most cost-effective source of the next increment of electricity, incremental $/ton removed is used in evaluating CAIR compliance to determine the most cost-effective source of the next increment of SO_2 or NOx reduction.

The incremental cost per ton removed is calculated by dividing the incremental levelized annual cost of compliance for each option by the incremental number of tons of SO_2 removed. Annual costs are defined to include incremental capital, O&M, fuel, consumables, waste disposal, by-product sales, and the cost of replacement capacity and energy. Incremental costs per ton are developed by comparing costs and emissions to the "previous" option in terms of cost per ton removed. As an example, if the least cost option to reduce emissions is to switch to compliance coal, the cost per ton removed would be calculated by dividing the incremental cost of burning compliance coal by the change in SO_2 emissions. The change in emissions would be based on the difference between a 1.8 lbs SO_2/mmBtu coal (if this was what the unit burned before the switch) and a 1.2 lbs SO_2/mmBtu compliance coal. In an incremental analysis, the next increment of SO_2 reduction should be analyzed assuming there has already been a switch to compliance coal. If the next increment of reduction was from the use of a scrubber, the cost per ton removed would be calculated as the incremental cost of the scrubber relative to the cost of using compliance coal, divided by the change in SO_2 emissions based on the difference between compliance coal of 1.2 lbs SO_2 /mmBtu (<u>not</u> 1.8 lbs SO_2/mmBtu coal) and the emission rate of the unit with the scrubber. Table 11-2 provides a numerical example and is discussed in the Unit Screening section, below.

The economic screening was completed in two steps:

- **Unit screening:** The first level of screening completed was a ranking of the options available at a single unit (e.g., a ranking of scrubbing and switching options for Crystal River 1). Scrubbing and fuel switching options that were "dominated" in terms of relative cost-effectiveness were eliminated and not considered in subsequent analyses. Dominated options are defined as those options that achieve less sulfur removal at a higher cost per ton removed than other alternatives. These options are not economic and should not be selected as part of a cost-effective system compliance plan. This is the most important purpose of economic screening.
- **System screening:** A second screening was performed to evaluate system-wide compliance. The compliance options remaining for each unit after the unit screening were ranked from lowest cost, on an incremental dollar per ton removed basis, to highest cost. This last level of screening provides an understanding of which system units are the least-cost candidates for emission control.

As with any economic analysis, a number of assumptions were used to perform this analysis. The cost assumptions of the technology options were developed in the process of technology screening. Fuel price assumptions were developed internally by the Company and are described in Chapter 8. The cost assumptions used in the screening analysis assume all units at a site are controlled using the same system. For example, in calculating the incremental cost of wet FGD systems at Crystal River, it was assumed that all of the units at Crystal River are scrubbed using wet FGD systems and using the same sulfur content coal. Other assumptions, such as the discount and escalation rates, are common planning assumptions.

Unit Screening

SO_2 Compliance Options

As shown in Table 11-1, above, the SO_2 compliance options evaluated consisted of fuel switching and scrubbing. Switching to a lower sulfur fuel oil and co-burning natural gas were evaluated for the Anclote units and partial-year burning of natural gas was evaluated at the small Suwannee River oil-fired steam units. Crystal River Units 1 and 2, which currently burn low sulfur coal (1.8 lbs SO_2/mmBtu), were evaluated burning compliance coal (1.2 lbs SO_2/mmBtu) from the CAPP region, similar to that currently being burned in Crystal River Units 4 and 5.

The scrubbing options were evaluated for two different fuel types. The specific options were to wet scrub either a 5 lbs SO_2 /mmBtu coal or a 4 lbs SO_2 /mmBtu coal, and to dry scrub either a 3 lbs SO_2 /mmBtu coal or a 1.8 lbs SO_2 /mmBtu coal. The variation of the coal sulfur content of the scrubbed coals was considered to confirm the general insight that it is more cost-effective to scrub a higher-sulfur coal. This is because the lower price of the higher-sulfur coal serves to offset the other costs of scrubbing.

Table 11-2 illustrates the screening process for a single unit, Crystal River Unit 1. The information presented was developed for each of PEF's coal and oil-fired units (except the units at the Bartow plant, which are being repowered). The first three columns of the table identify the unit, the SO_2 control option, and the fuel being assumed. The fourth column provides the total levelized revenue requirement cost of the option including capital, O&M, fuel, consumables, waste disposal, by-product sales, and the cost of replacement capacity and energy. The fifth column, labeled "Option Cost" is the cost of the option and is calculated as the Total Cost of the option less the total cost of the Base "option," which represents the current conditions of the unit. The SO_2 Emissions are estimated using the sulfur content of the fuel in the third column and based on the average capacity factor of the unit. It should be noted that the options in the table are sorted from highest to lowest emissions. The SO_2 Reduction column represents the reduction in SO_2 emissions provided by the option compared to the Base conditions, and the Average Cost ($/ton removed) is the Option Cost divided by the SO_2 Reduction. The Incremental Cost and Incremental Reductions are calculated as the cost and reduction of the option compared to the cost and reduction of the previous option in the table. Finally, the Incremental Cost ($/ton removed) is calculated by dividing the Incremental Cost by the Incremental Reduction.

Table 11-2. Example of Unit Screening

			Levelized Costs ($ Millions, 2005 $)							
Unit Name	Option Name	Fuel Name	Total Cost	Option Cost	SO2 Emissions (tons)	SO2 Reduction (tons)	Average Cost ($/ton removed)	Incremental Cost ($M)	Incremental Reduction (tons)	Incremental Cost ($/ton removed)
Crystal River 1	Base	1.8 lb coal	53.21	--	18620	--	--	--	--	--
Crystal River 1	Fuel switch	1.2 lb coal	57.14	3.93	12414	6207	634	3.93	6207	634
Crystal River 1	**Dry Scrub**	**3 lb coal**	**80.72**	**27.51**	**2690**	**15931**	**1727**	**23.57**	**9724**	**2424**
Crystal River 1	**Dry Scrub**	**1.8 lb coal**	**79.25**	**26.04**	**1862**	**16758**	**1554**	**-1.46**	**828**	**-1767**
Crystal River 1	Wet Scrub	5 lb coal	69.70	16.49	1570	17050	967	-9.56	292	-32755
Crystal River 1	Wet Scrub	4 lb coal	71.92	18.71	1241	17379	1077	2.22	329	6754

Dominated options

Results after removing dominated options

			Levelized Costs ($ Millions, 2005 $)							
Unit Name	Option Name	Fuel Name	Total Cost	Option Cost	SO2 Emissions (tons)	SO2 Reduction (tons)	Average Cost ($/ton removed)	Incremental Cost ($M)	Incremental Reduction (tons)	Incremental Cost ($/ton removed)
Crystal River 1	Base	1.8 lb coal	53.21	--	18620.42	--	--	--	--	--
Crystal River 1	Fuel switch	1.2 lb coal	57.14	3.93	12414	6207	634	3.93	6207	634
Crystal River 1	Wet Scrub	5 lb coal	69.70	16.49	1570	17050	967	12.56	10843	1158
Crystal River 1	Wet Scrub	4 lb coal	71.92	18.71	1241	17379	1077	2.22	329	6754

Table 11-2 illustrates the results of the unit screening and highlights the options that were "dominated" and thus eliminated from further analysis. In the case of Crystal River 1, the dry scrubber options are "dominated" because the cost of the options (shown in the fifth column of the tables, labeled "Option Cost") are higher than the cost of wet scrubber options and provide fewer SO_2 emission reductions. When these options are eliminated from the table, the incremental cost of the "Wet Scrub - 5 lb coal" option is recalculated. This same process was used for all of the Anclote, Crystal River, and Suwannee River units.

Based on the economic screening, several options were eliminated based on economics dominated. For the Anclote units, co-burning natural gas with 1.7 lbs SO_2/mmBtu was eliminated because co-burning 1.1 lbs SO_2/mmBtu oil with natural gas only slightly increases cost but with a proportionately larger reduction in SO_2 emissions; hence, a greater "bang for the buck." For the Crystal River units, the dry scrubbers were eliminated. The dry scrubbers were found to be about the same cost as wet scrubbers if fuel costs are not considered. While wet scrubber systems have higher capital and O&M costs than dry scrubber systems, dry scrubbers use a more expensive reagent (lime versus limestone for the wet scrubbers), and the dry scrubber systems produce a waste that must be disposed of, compared to gypsum that can be sold from the wet scrubbers. Adding all these costs together, the wet and dry systems have approximately the same cost. However, since dry scrubbers use lower sulfur, higher cost coals than wet scrubbers, the total cost of the dry scrubbers is greater than the total cost of the wet scrubbers.

NOx Compliance Options

Table 11-1 lists the NOx compliance options evaluated in the economic screening. The NOx compliance options evaluated consisted of fuel switching, burner modifications, and post-combustion controls. Partial-year burning of natural gas was evaluated at the small Suwannee River oil-fired steam units. Co-burning natural gas, LNBs with several different OFA configurations, and SCR controls were evaluated for the Anclote units. Crystal River Units 1 and 2 were evaluated with SNCR and SCR controls (the units currently have LNBs installed). LNBs, SNCRs and SCRs were evaluated for Crystal River Units 4 and 5.

The economic screening methodology described above was also used to eliminate non-economic NOx control options. For the Anclote units, the BOFA, ROFA, and co-burning of natural gas options were eliminated. BOFA is more costly and provides fewer NOx reductions than the CCOFA alternative. ROFA is more costly and provides fewer NOx reductions than the SOFA technology. Co-burning natural gas with BOFA, ROFA, and CCOFA was eliminated because burning gas results in significantly greater fuel costs while providing relatively fewer NOx reductions. SNCRs for the Crystal River units were eliminated because SCRs provide more NOx reductions at a proportionately lower cost. For Crystal River Units 4 and 5, three SCR systems were analyzed: an SCR by itself, resulting in a NOx rate of 0.06 lbs/mmBtu; a slightly smaller SCR in combination with LNBs resulting in a NOx rate of 0.06 lbs/mmBtu; and, a similar SCR as the first alternative but with LNBs installed, resulting in a NOx emission rate of 0.046 lbs/mmBtu. Of these three options, LNB/SCR with a NOx emission rate of 0.046 lbs/mmBtu had the lowest average dollar per ton of NOx removed cost; thus, the other two options were eliminated from consideration.

System Screening

SO_2 Compliance Options

The final step of the screening was to combine all of the remaining options into a system "supply curve" of options. Figure 11-2 presents this curve graphically for SO_2 reductions. As can be seen from the curve, beyond the approximately 100,000 ton level of reductions, further reductions in emissions can be achieved only at very high cost. These reductions are associated with scrubbing a 4 lbs SO_2/mmBtu coal at the Crystal River units. As discussed in Chapter 2, PEF projects that reductions in the range of 66,000 tons to 84,000 tons will need to be made annually (designated by the shading in the figure). Thus, the highest cost options were eliminated and the curve was re-drawn and is displayed as an inset in Figure 11-2 to get more detail at the lower end of the supply curve. Table 11-3 provides a listing of the options whose points are shown in the figure.

Figure 11-2. PEF SO_2 Reduction System Supply Curve

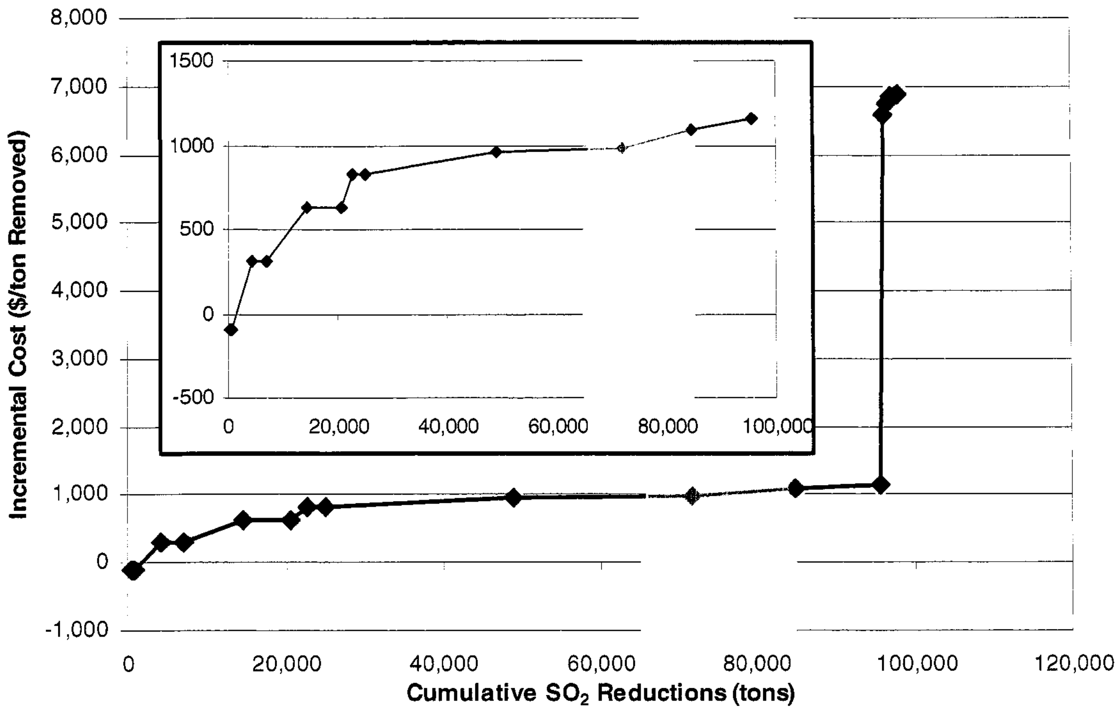


Table 11-3. SO_2 Compliance Options After Screening

Unit Name	Option Name	Fuel Name	Incremental Reduction (tons)	Incremental Cost ($/ton removed)	Cumulative Reductions (tons)
Suwannee 3	Fuel switch	1.1 lb oil-50% gas	379	-92	379
Suwannee 2	Fuel switch	1.1 lb oil-50% gas	220	-92	600
Suwannee 1	Fuel switch	1.1 lb oil-50% gas	216	-92	816
Anclote 1	Fuel switch	1.1 lb oil (A)	3,434	314	4,250
Anclote 2	Fuel switch	1.1 lb oil (A)	2,732	314	6,982
Crystal River 2	Fuel switch	1.2 lb coal	7,393	634	14,374
Crystal River 1	Fuel switch	1.2 lb coal	6,207	634	20,581
Anclote 2	Fuel switch	1.1 lb oil-40% gas	1,943	835	22,524
Anclote 1	Fuel switch	1.1 lb oil-40% gas	2,443	835	24,967
Crystal River 4	Wet Scrub	5 lb coal	23,888	963	48,855
Crystal River 5	Wet Scrub	5 lb coal	23,016	988	71,871
Crystal River 2	Wet Scrub	5 lb coal	12,915	1,089	84,786
Crystal River 1	Wet Scrub	5 lb coal	10,843	1,158	95,629
Crystal River 2	Wet Scrub	4 lb coal	392	6,600	96,021
Crystal River 1	Wet Scrub	4 lb coal	329	6,754	96,350
Crystal River 5	Wet Scrub	4 lb coal	698	6,865	97,048
Crystal River 4	Wet Scrub	4 lb coal	725	6,885	97,773

NOx Compliance Options

The system NOx reductions supply curve is shown in Figure 11-3. As with the SO_2 supply curve, reductions above 30,000 tons are very expensive. The high-cost options are SCR-based options on Anclote Units 1 and 2. As discussed in Chapter 2, PEF's projected annual NOx reduction requirements are in the range of 21,000 to 28,000 tons per year as indicated in the shading. Therefore, the control options above the 30,000 ton cumulative reduction level were eliminated and the curve was re-drawn as an inset to Figure 11-3. Table 11-4 provides a listing of the NOx control options whose points are shown in the figure.

Figure 11-3. PEF Annual NOx Reduction System Supply Curve

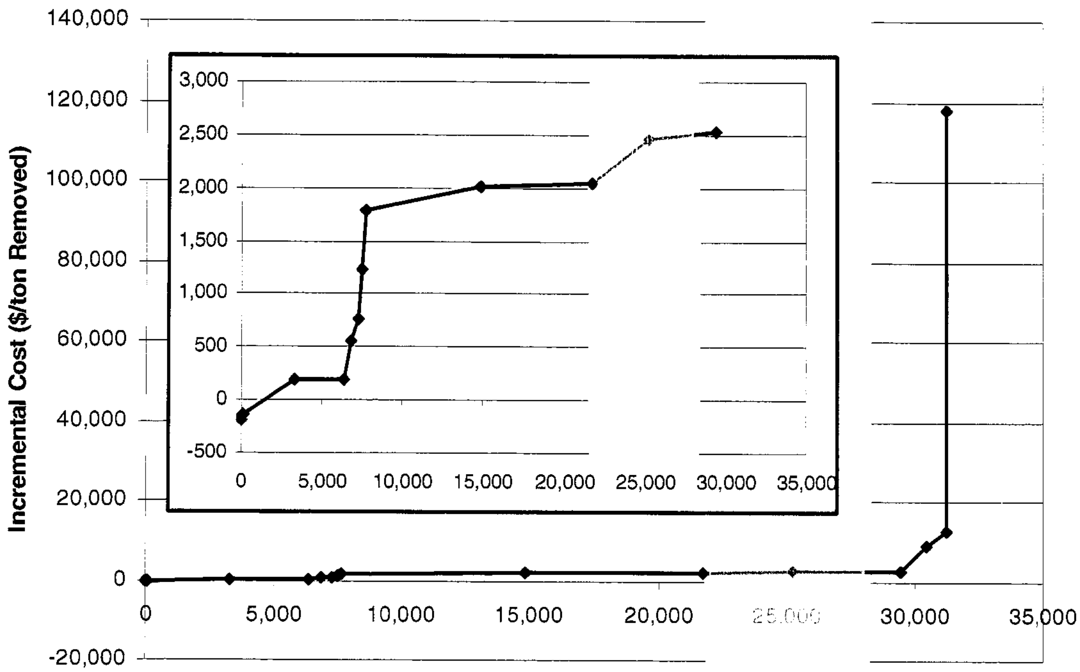


Table 11-4. NOx Compliance Options After Screening

Unit Name	Option Name	Fuel Name	Incremental Reduction (tons)	Incremental Cost ($/ton removed)	Cumulative Reductions (tons)
Suwannee 3	Fuel switch	1.1 lb oil-50% gas	26	-183	26
Suwannee 2	Fuel switch	1.1 lb oil-50% gas	17	-160	42
Suwannee 1	Fuel switch	1.1 lb oil-50% gas	19	-143	61
Crystal River 4	LNB	1.2 lb coal	3,191	189	3,252
Crystal River 5	LNB	1.2 lb coal	3,074	197	6,326
Anclote 1	LNB/CCOFA	1.7 lb oil	515	560	6,841
Anclote 2	LNB/CCOFA	1.7 lb oil	410	768	7,251
Anclote 1	LNB/SOFA	1.7 lb oil	229	1,232	7,480
Anclote 2	LNB/SOFA	1.7 lb oil	182	1,779	7,662
Crystal River 4	LNB/SCR (90%)	1.2 lb coal	7,156	2,005	14,818
Crystal River 5	LNB/SCR (90%)	1.2 lb coal	6,895	2,051	21,712
Crystal River 1	SCR	1.8 lb coal	3,528	2,458	25,240
Crystal River 2	SCR	1.8 lb coal	4,201	2,531	29,441
Anclote 1	LNB/SOFA/SCR	1.7 lb oil	973	9,022	30,414
Anclote 2	LNB/SOFA/SCR	1.7 lb oil	774	12,499	31,188
Anclote 2	LNB/SOFA/SCR	1.7 lb oil-40% gas	20	117,899	31,208
Anclote 1	LNB/SOFA/SCR	1.7 lb oil-40% gas	25	117,899	31,233

Conclusions

The two supply curves provide a simple presentation of the relative costs and reduction capabilities of the SO_2 and NOx control options available to PEF. The supply curves presented here provide a method for eliminating uneconomic compliance measures and providing an economic order of the options. However, the analysis presented in this chapter compares options based strictly on their cost per ton of pollutant removed. Since the supply curves are based on a static representation of the system (e.g., they do not capture the impact of possible changes in the dispatch of units once control measures are installed), they should only be used as a guide. Many other considerations are important in selecting a compliance plan, such as the risk of the options used and other environmental regulations. These, as well as other, factors need to be taken into consideration during the development of compliance strategies, and are discussed in Chapter 12. Chapter 12 will use the supply curves presented here to develop alternative compliance plans and will compare the cost of emission reductions to the cost of allowances.

Chapter 12 Evaluation and Results

Introduction

The purpose of this chapter is to discuss the development and evaluation of alternative plans to comply with CAIR, CAMR, and CAVR. The first section discusses the methodology used to develop alternative plans, as well as the methods and tools used to evaluate them. The second section discusses PEF's approach to compliance with the regulations and five alternative plans developed by PEF. The third section discusses the quantitative analysis of the plans, providing projections of emissions associated with each of the alternative plans and the cumulative present value of revenue requirements (CPVRR) cost impacts of the plans. Each plan is also assessed from a qualitative standpoint. The chapter closes with the identification of the plan PEF will pursue for compliance with CAIR, CAMR, and CAVR.

Overview of Methodology

As discussed in Chapter 2, PEF's emissions are significantly greater than the number of allowances that PEF either has or expects to receive. Depending on the final regulations promulgated by the Florida DEP, PEF will have to significantly reduce SO_2, NOx and mercury emissions, purchase a significant number of allowances, or employ a combination of controls and allowance purchases. As discussed in Chapter 9, the market for allowances has a significant amount of volatility and uncertainty in the price, making a plan that relies on significant purchases of allowances inherently risky. PEF developed alternative compliance plans that would reduce emissions consistent with the number of allowances expected to be received, or would reduce the number of allowances that would be need to be purchased to an acceptable level of risk.

The alternative plans were developed with the aid of the SO_2 and NOx supply curves developed in Chapter 11. The supply curves identified the cost and emission reduction characteristics associated with specific measures or controls for PEF's highest emitting units. In general, emission reduction measures were selected and included in a plan by proceeding from the least cost measure at the top of the list (see Tables 11-3 and 11-4) to the highest cost measures until the cumulative reductions reached the expected number of reductions needed to comply. If emission allowance markets were more liquid and stable, and the price of allowances could be projected with confidence, the purchase of allowances would also be considered as a compliance measure and included in the mix considered in a plan. In that situation, control or fuel switch measures would be selected from the list to the point where the expected cost of purchasing allowances is less expensive than the incremental cost of adding emission controls to the units. At that point, allowances would be purchased to the extent needed for compliance. However, since allowance markets are not liquid and stable at this point in time, PEF cannot rely on being able to purchase allowances in the quantities needed for compliance. Hence, plans were developed that did not overly rely on purchasing allowances.

A few limitations of the supply curves must be kept in mind. First, the incremental reductions identified in the tables are based on average expected operation of the units in the future. As shown in Figures 2-7, 2-8, and 2-9, PEF's emissions vary from year to year, because units operate at different levels each year. Second, the incremental reductions were calculated based on the average expected operation of the units *prior* to the installation of the control measures. After controls are added or the fuel used changes, the dispatch of units will likely change, which, in turn, will change how much units will operate. This will result in a different amount of emissions, and effectively the amount of reductions achieved. Third, the supply curves do not take into account banking of leftover allowances in years when emissions are lower than the number of allowances received and the use of the bank in future years when emissions are greater than the number of allowances received. All of these factors may result in the need for more, or fewer, controls than indicated by the screening curves.

Once the alternative plans were developed, the plans were simulated using PEF's detailed production costing model, PROSYM, through the year 2025. The PROSYM model simulates the operation of each generating resource on the PEF system, both existing and future, and how it is used to serve the forecasted peak demand and energy requirements of PEF's customers. The emission reduction characteristics of each control (scrubbers, SCRs, etc.) were applied to the selected units in the alternative plans, and the resultant operation was simulated. PROSYM projects how much the units will be dispatched given their new characteristics, constraints, limitations, and fuel prices, and how they will interact with the other units in the PEF generating system. The results from PROSYM include projected generation and purchases, fuel usage, fuel and purchased power cost, reagent consumption, waste and by-product generation, and emissions of SO_2, NOx and mercury. The production costs (fuel, purchased power, reagent, and by-product) of each alternative plan were compared to the production costs of the Baseline forecast (without emission controls) to determine the change in production costs for each alternative compliance plan.

The costs of compliance (other than the fuel and purchased power, reagent, and by-product costs that are determined by PROSYM) were developed by performing a detailed economic analysis of each control measure. These costs included the capital and O&M costs associated with the control measures used in the alternative plans (see Chapters 4, 5, and 6 for the identification of the capital and O&M costs associated with the control measures). "Life-cycle" analyses were performed through the end of 2038, capturing the entire book life of the longest-lived measure (a scrubber or SCR installed on Crystal River Unit 4 or 5). The production costs were extrapolated from 2025 to 2038 assuming the PEF generating resources continue operating as they did in 2025. The prices of fuel, O&M, consumables, and by-products were escalated using standard corporate escalation rates (e.g., 2.5 percent for O&M) or the compound growth rates of the item over the last years of the respective price forecast.

The analyses calculated the revenue requirements associated with the controls selected for each alternative plan. These revenue requirements were then combined with the change in production costs to determine the total revenue requirements for each alternative plan. The CPVRR was then used to compare the economic cost of the alternative plans.

Plan Development

Approach to Compliance

PEF's approach to SO_2 and NOx compliance is to reduce emissions in the most cost-effective manner using proven, reliable technologies. Because SO_2 and NOx allowance markets are volatile and the future price of allowances is uncertain, PEF will pursue a compliance strategy that reduces emissions rather than one that relies substantially on purchasing allowances for compliance. This is not to say that PEF won't use the allowance markets to some extent. Depending on the expected cost of allowances, if the expected savings from purchasing allowances is significantly greater than the cost of switching fuels or installing control systems so as to justify the risk associated with volatile allowance prices, PEF may use allowance purchases for some of its compliance strategy.

As discussed in Chapter 2, the four Crystal River coal units produce up to 80 percent of PEF's SO_2 and NOx emissions subject to CAIR regulations, and all of the mercury emissions subject to CAMR regulations. Thus, in order to comply with the regulations without significant allowance purchases, changes will have to be made at some, if not all, of the four units at Crystal River. As discussed in Chapters 4 and 5, there are a limited number of control technologies that are proven, reliable and practical. Chapter 11 identifies 17 SO_2 compliance options from which PEF can choose after uneconomical options have been screened out. Seven of the options provide less than 750 tons of reductions each. Seventeen NOx control options are also available after screening out uneconomical measures, and five of these reduce less than 50 tons of NOx each. This demonstrates that PEF's emission control options that can produce substantial SO_2 and NOx emission reductions are truly limited, and the number of possible combinations of measures needed to reduce emissions down to the number of allowances PEF expects to hold is limited even further.

As discussed in Chapter 6, predicting mercury reductions is extremely challenging. There are many variables that are known to impact the mercury removal performance. Although a number of these variables have been identified, not all of their impacts to mercury removal performance are clearly understood. PEF's approach to CAMR compliance is based upon an evaluation of the following mercury reduction technologies:

- Co-Benefit mercury control provided by the existing particulate control devices;
- Co-Benefit mercury control of the planned NOx and SO_2 reduction technologies;
- Mercury-specific control provided by injection of activated carbon or other sorbent.

In addition to controls, Continuous Emissions Monitors for Mercury will be required by January 1, 2009. These monitors are currently in the evaluation phase and, in fact, Progress Energy is providing a host site to further the accurate evaluation of the technologies.

Development of Alternative Plans

To develop alternative compliance plans, PEF used the SO_2 and NOx screening curves to assemble various combinations of compliance measures that would produce the required emissions reductions. In general, the screening curves in Figures 11-2 and 11-3 (and Tables 11-3 and 11-4) were used to select the measures based on their incremental costs of reduction. Options were selected from the list, going from the lowest incremental cost per ton removed up to higher cost until the cumulative reductions were to the expected levels required for compliance.

As discussed in Chapter 2, PEF expects to need to reduce SO_2 emissions in the range of 66,000 tons to 84,000 tons annually. As shown in Figure 11-2, to achieve 66,000 tons of reductions, all measures in Table 11-3 down to and including wet scrubbers on Crystal River Unit 5 will be needed for compliance. To achieve compliance at the 84,000 ton reduction level, scrubbers will be required for Crystal River Unit 2. As noted in Table 11-3, when the units are scrubbed, they will be capable of burning a higher sulfur coal. Based on this analysis, to achieve compliance with CAIR without relying on allowances, PEF will need to install scrubbers on at least three of the four Crystal River units.

For compliance with the NOx requirements of CAIR, PEF expects to have to make annual reductions in the range of 21,000 tons to 28,000 tons and ozone season NOx reductions of 10,000 tons to 14,000 tons. Figure 11-3 shows that to achieve the minimum level of reductions, all measures in Table 11-4 down to, and including, low NOx burners with SCRs on Crystal River Unit 5 will be needed for compliance. Adding SCRs on Crystal River Unit 1 will provide total annual reductions to approximately 25,000 tons, as shown in Table 11-4. Based solely on the screening curves and ignoring their limitations (as discussed above), to comply with the NOx portion of CAIR without relying on allowances, PEF will need to install SCRs on at least three of the four Crystal River units.

Since scrubbers and SCRs are likely to be necessary on three of the Crystal River units for compliance without purchasing SO_2 and NOx allowances, PEF expects to be able to comply with CAMR through the synergistic mercury reduction effect of scrubbers and SCRs without any additional mercury-specific controls, at least through Phase I of CAMR. As shown in Figure 2-9, PEF's annual mercury emissions are currently projected to be around 600 pounds. The first phase of CAMR requires PEF to reduce emissions by approximately 130 pounds. The sum of the emissions from Crystal River Units 2, 4, and 5 are approximately equal to 400 pounds. If the combination of wet scrubbers and SCRs reduces mercury emissions by 80 percent, PEF would achieve reductions of 320 pounds per year from the three units. This simple calculation does not take into consideration the higher levels of mercury present in the higher sulfur coals the units will be capable of burning after the scrubbers are installed (relative to the mercury content in the compliance coals they currently burn); however, the reductions should be sufficient to comply with the first phase of CAMR, at a minimum.

In addition to CAIR and CAMR, PEF must comply with the BART requirements of the CAVR. These requirements apply to Crystal River Units 1 and 2 and to Anclote Unit 1. As discussed in Chapter 2, the presumptive BART emission limits would require scrubbers on Crystal River Units 1 and 2 for SO_2 and SCRs or SNCRs for those units for NOx. Because EPA's final CAVR rule provides that compliance with the EPA cap-and-trade program for CAIR may satisfy BART requirements, it may not be necessary to install scrubbers and SCRs or SNCRs on both units. At this time, however, it is uncertain whether the Florida DEP will adopt the EPA cap-and-trade program.

The considerations outlined above were used to develop five alternative compliance plans. These plans are described below and are outlined in Table 12-1. If construction and installation of emission controls could be done instantaneously, NOx controls would be installed on January 1, 2009 and SO_2 controls would be installed on January 1, 2010 according to the deadlines set by CAIR. Obviously, construction can not be performed overnight, and the real-life limitations of space, qualified manpower, material procurement, and scheduled maintenance outages necessitate the installation of controls to be spread out over time and, in most cases, several months or years ahead of the deadlines set by CAIR. Therefore, the alternative plans had to take these constraints into consideration.

Plan A

Plan A is consistent with the preliminary compliance plan that PEF developed in 2005. This plan assumes that PEF will scrub all four units at Crystal River in order to comply with both CAIR and the BART requirements of CAVR. Installation of all four scrubbers is expected to reduce SO_2 emissions by approximately 84,000 tons per year, on average. With this level of reduction from these four scrubbers, other emission reduction measures that have lower incremental reduction costs will not be needed. The NOx portion of Plan A also assumes SCRs will have to be placed on all four units at Crystal River and that LNB/SOFA systems will be installed on the Anclote units for compliance with CAIR and CAVR. Installation of all these controls is expected to reduce NOx emissions by over 29,000 tons per year, on average, which is more than the maximum amount of reductions anticipated to be needed in any year.

For the SO_2 portion of this plan, wet scrubbers with 97 percent removal efficiency are assumed to be installed on Crystal River Units 5 and 4 by April 2009 and November 2009, respectively. Crystal River Unit 2 will have a wet scrubber installed by April 2011 and Crystal River Unit 1's scrubber is assumed to be installed by April 2012. Prior to the installation of scrubbers, Units 1 and 2 will switch to a lower sulfur, "compliance" coal containing 1.2 lbs SO_2 /mmBtu. This switch is necessary to reduce system SO_2 emissions below the number of allowances, as is the switch to a lower sulfur oil at the Anclote units.

The NOx part of the plan has LNB/SCR systems being installed on Crystal River Units 4 and 5 by April 1, 2008 and April 2009, respectively. Crystal River Units 1 and 2 will have their SCRs installed by March 2011 and March 2012, respectively. LNB/SOFA systems will be installed on Anclote Unit 1 by November 2008 and on Unit 2 by March 2009.

No dedicated mercury controls are included in this plan. The combination of wet scrubbers and SCRs on the Crystal River units is expected to remove 80 percent of the mercury emissions from the flue gas.

Plan B

Plan B assumes that complying with CAIR will meet the requirements of CAVR. Thus, Crystal River Unit 1 will not be scrubbed, and instead, will continue to burn compliance coal throughout the planning period. Crystal River 1 will not to be scrubbed because it is projected to have a higher incremental reduction cost than Crystal River Unit 2, as shown in Table 11-3. Plan B includes the burning of lower sulfur oil at both Anclote units, since the incremental cost is one of the lower-cost measures for reducing SO_2 emissions available to PEF, according to Table 11-3. The lower sulfur oil will be used during only some years, as required to bring emissions below the number of allowances received each year. Using the estimated incremental reductions shown in Table 11-3, these measures should provide more than 79,000 tons of SO_2 reductions, on average. It should be noted that Table 11-3 shows that burning 40 to 50 percent natural gas along with low sulfur oil at the Suwannee River and Anclote units could provide over 5,200 tons of SO_2 reductions at a lower incremental cost than scrubbing any of the Crystal River units. While these are lower-cost reductions, the 5,200 tons of reductions are not enough to eliminate the need for any of the scrubbers. Therefore, burning natural gas provides reductions that are not required, and thus, is not included in the plan.

The NOx portion of Plan B includes SCRs at Crystal River Units 2, 4, and 5 and LNB/SOFA systems at Anclote Units 1 & 2. These measures are expected to provide annual NOx reductions of over 25,800 tons, on average, according to Table 11-4. While Table 11-4 shows that an SCR at Crystal River 1 is lower-cost than an SCR at Crystal River 2, to obtain the mercury reduction synergies of wet scrubbers and SCR systems, the SCR on Crystal River 2 was chosen instead of an SCR at Unit 1. As shown in Table 11-4, burning natural gas at the Suwannee River units would provide the lowest-cost NOx reductions. However, the small number of reductions (62 tons) is not enough to eliminate the need of any of the more expensive options; thus choosing these options would only add extra cost to the Plan.

Plan B requires the addition of a PAC injection system on Crystal River Unit 1 to remain compliant with CAMR through the end of 2025.

The installation dates of the measures used in Plan B are outlined in Table 12-1.

Plan C

Plan C is similar to Plan B with the exception that a scrubber and SCR are installed on Crystal River Unit 1 instead of Unit 2. Site conditions at Crystal River are such that adding controls to Crystal River Unit 2 would make it extremely difficult to install controls on Unit 1 at a later date. Therefore, adding controls on Unit 1, as assumed in this plan, will allow PEF the ability to put controls on Unit 2, if necessary, at a later date. Under this plan, Crystal River Unit 2 burns compliance coal throughout the planning period. Since Crystal River Unit 1 is smaller than Unit 2, additional emission reductions will be needed. Therefore, Anclote Units 1 and 2 will burn lower sulfur oil beginning in 2010 and throughout the planning period. Because Plan C does not control both Crystal River Units 1 and 2, it relies on the premise that complying with CAIR will mean compliance with BART.

Plan C requires the addition of a PAC injection system on Crystal River Unit 2 to remain compliant with CAMR through the end of 2025.

Plan D

Plan D includes wet scrubbers and SCRs on Crystal River Units 4 and 5, burning compliance coal at Units 1 and 2, and burning low sulfur oil and natural gas at Anclote Units 1 and 2 throughout the planning period, starting in 2010. LNB/SOFA controls will be installed on the Anclote units for NOx reductions. These control options are among the lowest-cost options in Tables 11-3 and 11-4 and provide most, but not all, of the reductions required. Unlike Plans A, B, and C, Plan D was developed with the idea that PEF would rely to some extent on purchasing allowances for CAIR compliance. Like Plans B and C, Plan D relies on the premise that compliance with CAIR will satisfy BART requirements. For CAMR compliance, a PAC injection system is planned for Crystal River Unit 2 in 2017.

Plan E

Plan E takes a different approach to compliance than all the other plans, in that it focuses on installing controls on Crystal River Units 1 and 2 and Anclote Unit 1 for CAVR compliance and purchasing allowances for CAIR compliance. Plan E calls for the installation of wet scrubbers and SCRs on Crystal River Units 1 and 2, as well as burning low sulfur oil and natural gas and installing LNB/SOFA controls at Anclote. Crystal River Units 4 and 5 are assumed to continue to burn 1.2 lbs SO_2/mmBtu coal they currently burn. In Plan E the units will have PAC injection systems installed for mercury control.

Table 12-1. Summary of Alternative Compliance Plans

	Plan A	Plan B	Plan C	Plan D	Plan E
SO_2 Plan					
Anclote 1	Fuel switch 1.1 lb oil starting 2010	Fuel switch 1.1 lb oil various years starting 2010	Fuel switch 1.1 lb oil starting 2010	Fuel switch 1.1 lb oil and 40% gas starting 2010	Fuel switch 1.1 lb oil and 40% gas starting 2010
Anclote 2	Fuel switch 1.1 lb oil starting 2010	Fuel switch 1.1 lb oil various years starting 2010	Fuel switch 1.1 lb oil starting 2010	Fuel switch 1.1 lb oil and 40% gas starting 2010	Fuel switch 1.1 lb oil and 40% gas starting 2010
Crystal River 1	Fuel switch 1.2 lb coal 2010 until scrub Scrub 3/2012	Fuel switch 1.2 lb coal starting 2010	Fuel switch 1.2 lb coal 2010 until scrub Scrub 4/2015	Fuel switch 1.2 lb coal starting 2010	Scrub 4/2010
Crystal River 2	Fuel switch 1.2 lb coal 2010 until scrub Scrub 3/2011	Fuel switch 1.2 lb coal 2010 until scrub Scrub 4/2014	Fuel switch 1.2 lb coal starting 2010	Fuel switch 1.2 lb coal starting 2010	Scrub 10/2010
Crystal River 4	Scrub 11/2009	Scrub 11/2009	Scrub 11/2009	Scrub 11/2009	Burn 1.2 lb coal
Crystal River 5	Scrub 4/2009	Scrub 4/2009	Scrub 4/2009	Scrub 4/2009	Burn 1.2 lb coal
NOx Plan					
Anclote 1	LNB/SOFA 11/2008	LNB/SOFA 11/2008	LNB/SOFA 11/2008	LNB/SOFA 11/2008	LNB/SOFA 11/2008
Anclote 2	LNB/SOFA 3/2009	LNB/SOFA 3/2009	LNB/SOFA 3/2009	LNB/SOFA 3/2009	LNB/SOFA 3/2009
Crystal River 1	SCR 3/2012		SCR 4/2012		SCR 4/2010
Crystal River 2	SCR 3/2011	SCR 3/2011			SCR 10/2010
Crystal River 4	LNB/SCR 4/2008	LNB/SCR 4/2008	LNB/SCR 4/2008	LNB/SCR 4/2008	
Crystal River 5	LNB/SCR 4/2009	LNB/SCR 4/2009	LNB/SCR 4/2009	LNB/SCR 4/2009	
Mercury Plan					
Crystal River 1	FGD/SCR synergy	PAC 1/2024	FGD/SCR synergy		FGD/SCR synergy
Crystal River 2	FGD/SCR synergy	FGD/SCR synergy	PAC 1/2022	PAC 1/2017	FGD/SCR synergy
Crystal River 4	FGD/SCR synergy	FGD/SCR synergy	FGD/SCR synergy	FGD/SCR synergy	PAC 1/2017
Crystal River 5	FGD/SCR synergy	FGD/SCR synergy	FGD/SCR synergy	FGD/SCR synergy	PAC 1/2010
Allowances				Rely on purchases	Rely on purchases

Key:
Scrub = Wet scrubber with 97% SO2 removal efficiency
Fuel designations refer to lb SO2 per mmBtu
PAC = Powdered Activated Carbon injection system

Plan Evaluation

This section provides both a quantitative and qualitative analysis of the alternative compliance plans. The quantitative analysis includes an examination of the projected emissions of the plans and the impact on costs, in terms of cumulative present value of revenue requirements.

Quantitative Analysis of Alternative Compliance Plans

Environmental Compliance

The compliance achieved by each plan for CAIR and CAMR will be demonstrated with a series of charts. In the charts, the projected emissions of SO_2, NOx, and mercury are shown as a red line. The expected allowances are shown by an orange line, and the balance of allowances at the beginning of each year (BOY) is represented by a blue line. For SO_2, the line showing allowances actually represents "emission-equivalent" allowances. Emission-equivalent allowances are the number of allowances divided by the "CAIR factor." The CAIR factor is the number of allowances that must be "redeemed" for each ton of SO_2 emissions. The value of the CAIR factor is 2.0 from 2010-2014 and 2.86 beginning in 2015 and beyond. The balance of allowances represents the allowances PEF has at the beginning of each year, and is the sum of the allowances received at the beginning of each year and the difference between PEF's emissions and allowances in previous years. To the extent PEF's emissions are lower than the number of allowances received, the difference goes in the "bank" and is available for PEF's use in future years should emissions be greater than the number of allowance received in that year.

Plan A

The projected PEF system emissions of SO_2, NOx (both annual and ozone season), and mercury for Plan A are shown in Figure 12-1. With the exception of NOx emissions in 2009 and 2010 and mercury emissions starting in 2018, Plan A would reduce emissions to levels below the number of allowances PEF expects to receive in all years. The figure shows the preliminary compliance plan developed by PEF in 2005, which was based on earlier projections, would provide significantly greater reductions than are now projected to be required. As discussed in Chapter 2, the assumptions of new coal and nuclear unit additions by PEF has reduced the projected emissions. Therefore, under the assumptions of load growth and new generation additions made for this study, controlling emissions on all four Crystal River units will not be necessary for PEF to comply with CAIR in the long term. In addition to SO_2 and NOx, mercury emissions are controlled through 2025, assuming reductions prior to 2018 are allowed to be banked and used after 2018. If, however, PEF is not allowed to bank mercury allowances, controls specifically designed to reduce mercury emissions will need to be added to the Crystal River units prior to 2018.

Plan B

The projected PEF system emissions associated with Plan B are shown in the charts of Figure 12-2. Compared to Plan A, PEF's SO_2 and NOx emissions under this plan more closely match the CAIR allowances. There are years in which the emissions are greater than the number of allowances; however, the analysis assumes PEF will use its bank of allowances to remain in compliance. Through 2025, PEF's reductions are greater than required under CAIR, as evidenced by the allowance balances being greater than the projected emissions in 2025.

Figure 12-1. Plan A Emission Projections

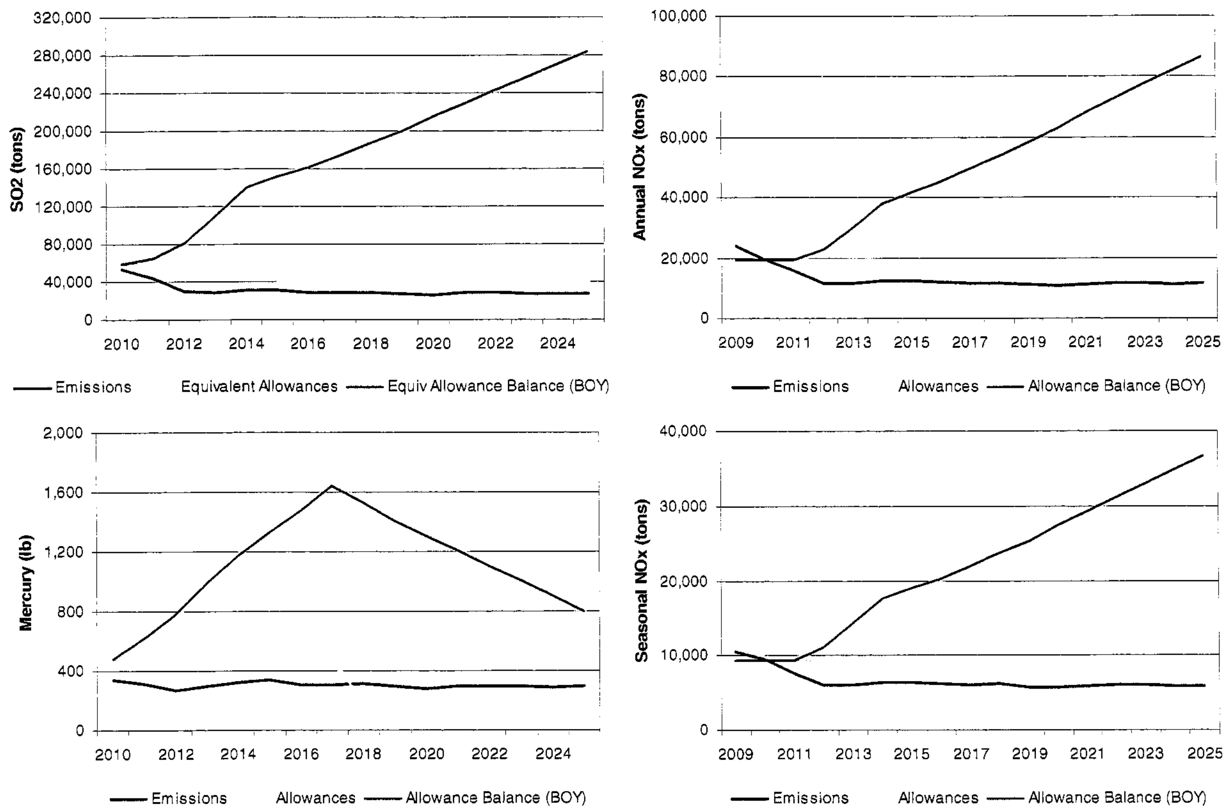
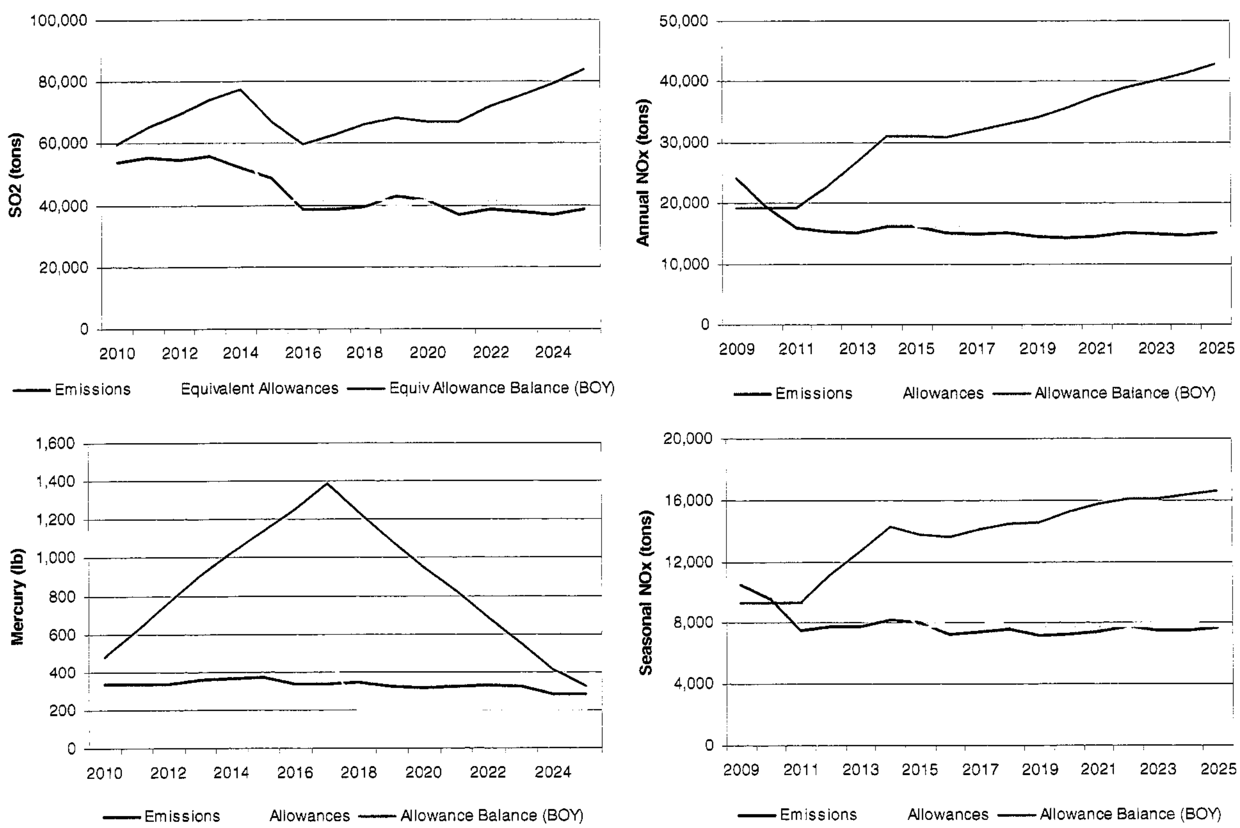


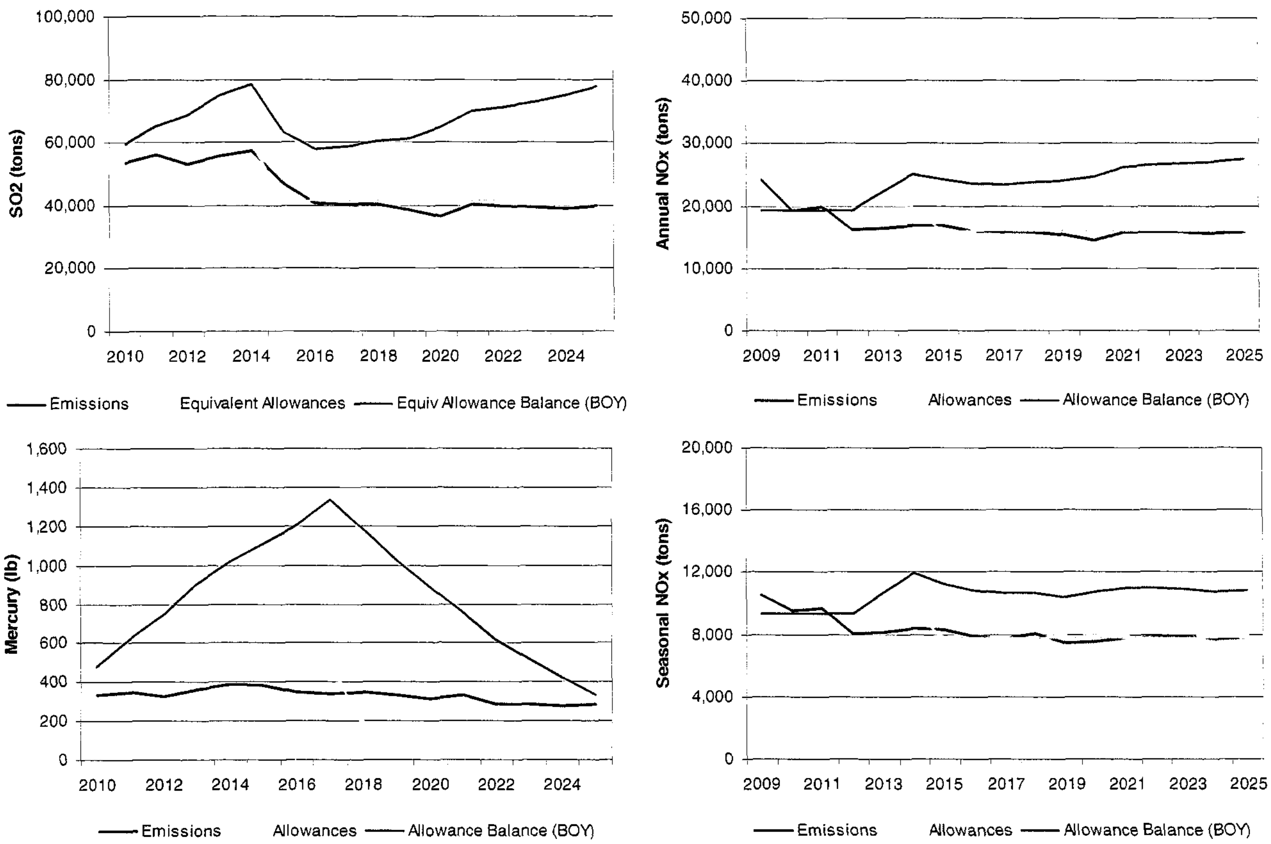
Figure 12-2. Plan B Emission Projections



Plan C

Plan C, which adds controls to Crystal River 1 instead of Crystal River 2 as in Plan B, provides an even better match between emissions and allowances compared to Plans A and B, as shown in Figure 12-3. The allowance balance at the end of the study is smaller because controlling Unit 1, which is smaller than Unit 2, does not reduce emissions as much as Plan B. Still, the SO_2 and NOx allowance balances at the end of 2025 are significantly greater than projected emissions. The mercury allowance balance, on the other hand, is only slightly higher than the projected emissions. With this plan, PEF has the flexibility to advance the PAC injection system on Crystal River Unit 2 to an earlier year, if necessary.

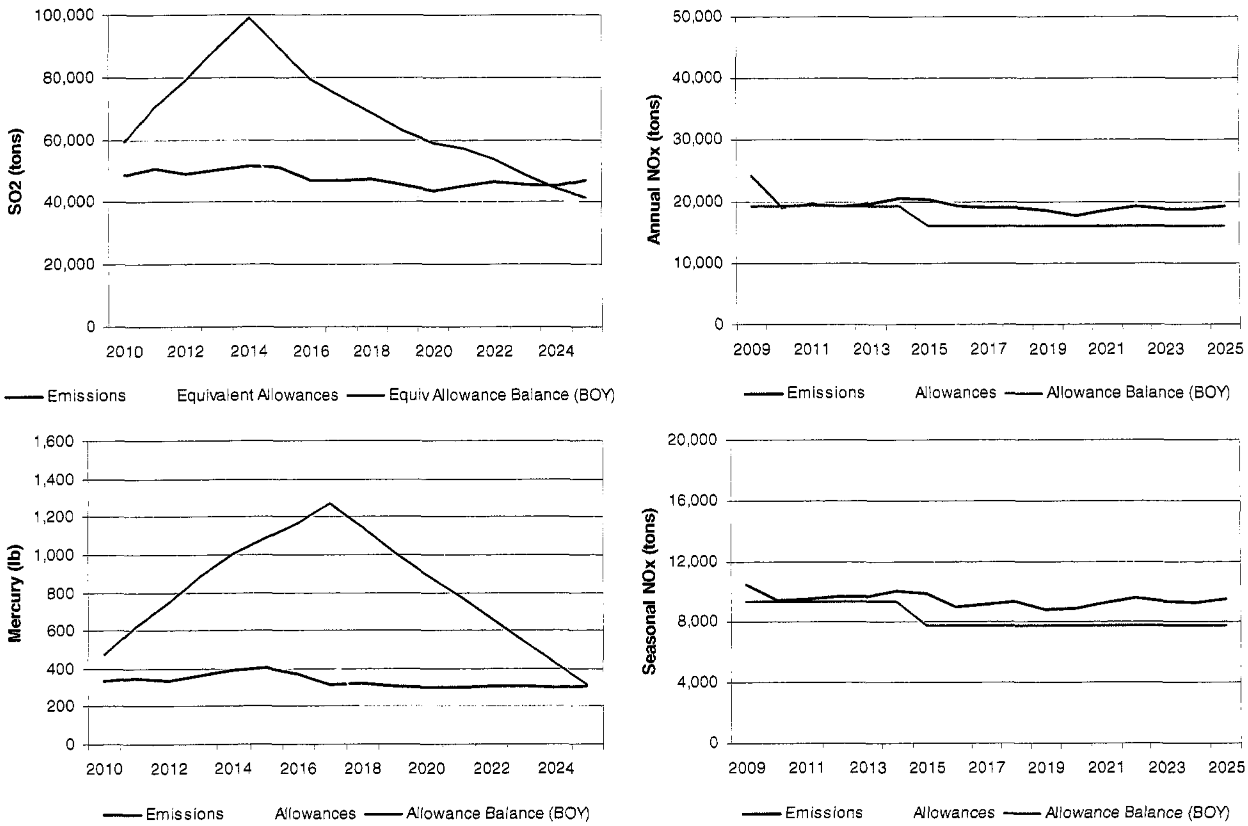
Figure 12-3. Plan C Emission Projections



Plan D

Plan D is the first plan designed with the purchase of allowances for CAIR compliance in mind. The charts in Figure 12-4 show PEF's SO_2 emissions beginning in 2015 to be greater than the number of allowances received. The SO_2 allowance bank is depleted after 2023 and PEF must purchase approximately 15,000 allowances per year starting in 2024. PEF's NOx emissions under Plan D are greater than or equal to the number of allowances it will receive in most of the years. Approximately 3,000 annual and 1,500 ozone season NOx allowances will need to be purchased annually starting in 2015. (Note that the blue allowance balance line in the NOx charts lies on top of, and hides, the gold allowance line since there are no NOx allowances in the bank in any year; therefore, the allowance balance at the beginning of the year is just the number of allowances received by PEF at the beginning of the year.) For mercury, the allowance balance is only slightly above zero at the end of 2025. In Plan D, PAC injection systems are installed on Crystal River 2 in 2017. PEF has the ability to add controls to Crystal River Unit 1 or advance the controls on Unit 2, if necessary.

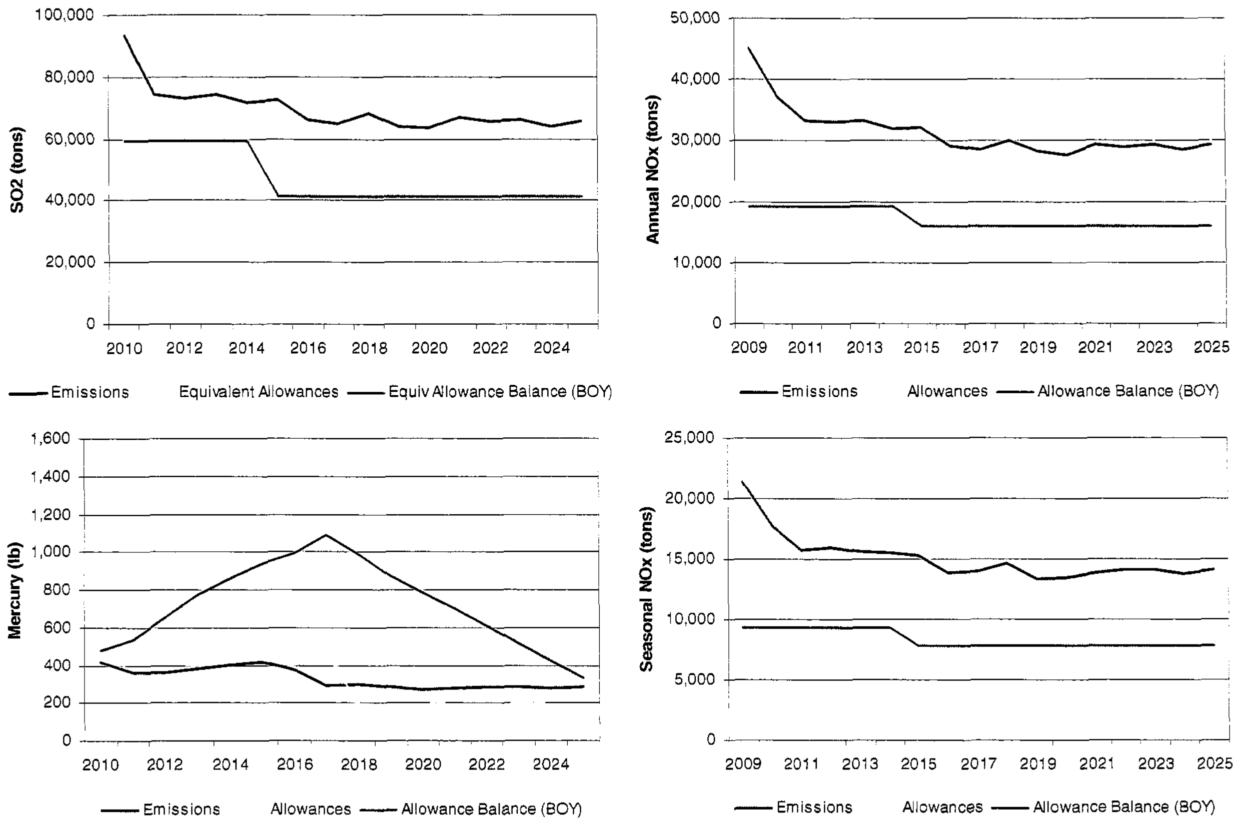
Figure 12-4. Plan D Emission Projections



Plan E

In Plan E, PEF utilizes SO_2 and NOx control measures only on BART-affected units (Anclote 1 and Crystal River Units 1 and 2). The charts in Figure 12-5 show that under this plan, PEF's emissions are greater than the SO_2 and NOx allowances it receives in all years. PEF must purchase approximately 28,000 SO_2 allowances annually between 2010 and 2015, and more than 70,000 allowances per year after 2015. For NOx, PEF must purchase more than 13,000 annual and 6,000 ozone season allowances per year starting in 2009. For mercury, PEF's emissions are less than the number of allowances through 2017. Under this plan, PEF's bank of allowances is sufficient to cover PEF's mercury emissions through 2025.

Figure 12-5. Plan E Emission Projections



Economic Impact of Compliance

As described above, the economic impact of the alternative compliance plans were compared using the CPVRR. Figure 12-6, below, shows the CPVRR of Plans A through E. Included in the CPVRR are the projected capital and O&M costs associated with controls, the projected cost of reagents (limestone and ammonia), credits for the sale of by-products (gypsum), the projected change in fuel and purchased power costs compared to the Baseline projection, and the projected cost of purchasing allowances. The figure shows Plan A to be the most expensive plan. The high cost of Plan A is largely due to the capital costs associated with the emission controls installed, which are shown in Figure 12-7. Plans B and C, which also comply with CAIR without long-term purchases of allowances, are less costly than Plan A. This result is expected because only three of the Crystal River units have emission controls installed, and the projection of emissions more closely matches the number of allowances. This was seen in Figures 12-2 and 12-3 by the balance of allowances remaining close to, and not significantly exceeding, the number of allowances received. Plan D is the plan with the lowest cumulative present value of revenue requirements. Plan D strikes a balance between installing controls and buying allowances by adding controls to the two largest coal units on the PEF system. It is noteworthy that Plan E is more costly than Plan D, even though the capital requirements are considerably less than any other plan. This is caused by the significant amount of allowance purchases that would be required.

Figure 12-6. Comparison of Cumulative Present Value of Revenue Requirements

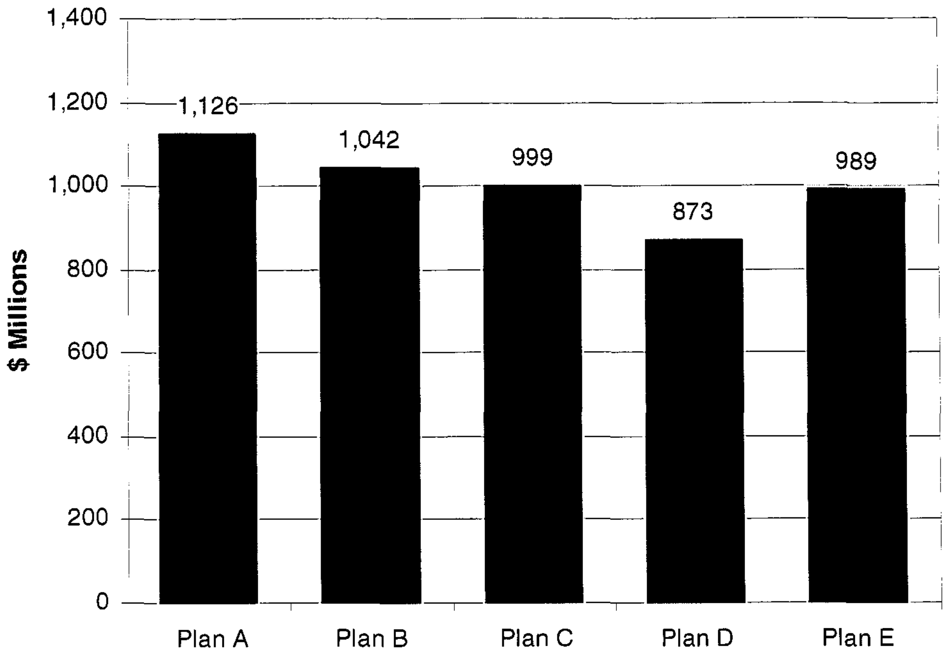


Figure 12-7. Total Capital Expenditures of Plans

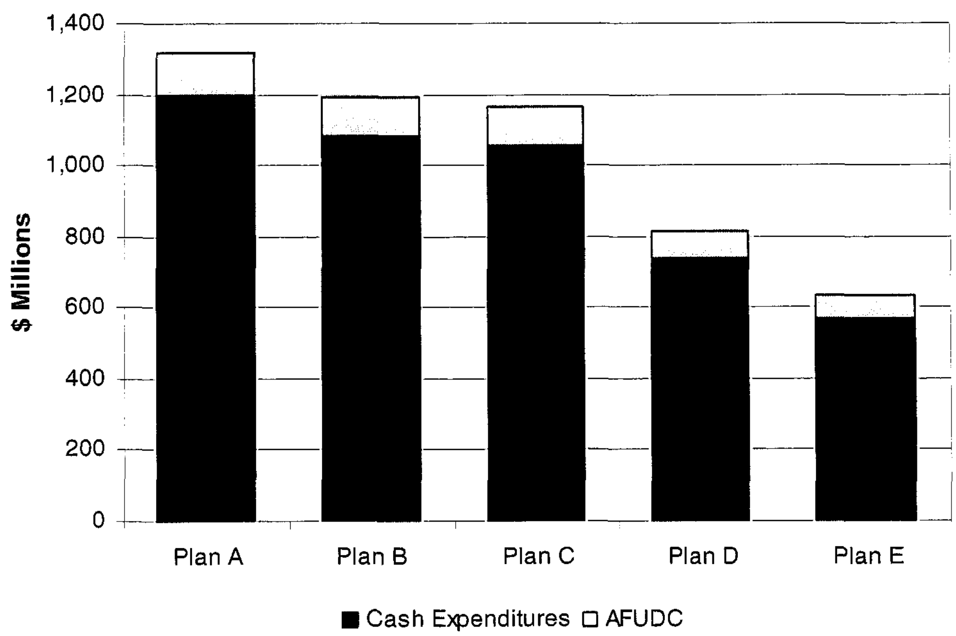
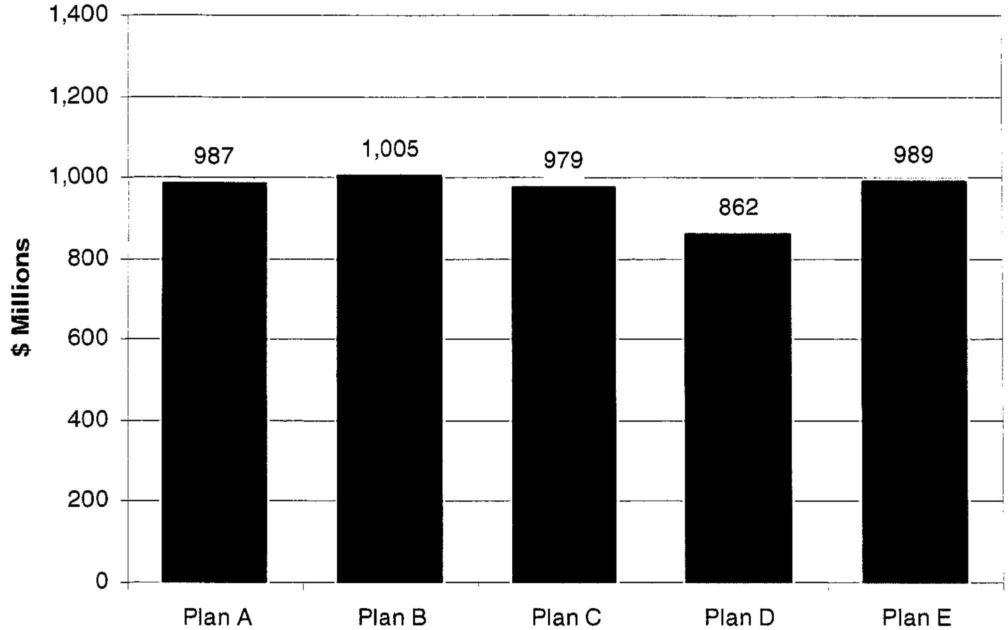


Figure 12-6 includes the cost of allowances purchased for compliance with CAIR. However, the value of allowances left in the bank is not included in Figure 12-6. To place the plans on an economic level playing field, the value of the bank needs to be captured. Figure 12-8 incorporates this economic value by assuming allowances are either sold or purchased each year. In this manner, the cost of installing extra controls, such as in Plan A, can be offset by selling any allowances available at the end of each year.

Figure 12-8. CPVRR Comparison Including Allowance Sales



By selling allowances rather than banking them, the cost of Plans A through D are reduced; the cost of Plan E does not change since allowances are always purchased and never sold. The cost of Plans A, B, C, and E are considerably closer and are almost the same. The cost of Plan D also dropped slightly, reflecting the sale of allowances in the early years. After factoring the value of the allowance bank, Plan D is still the plan with the lowest cost.

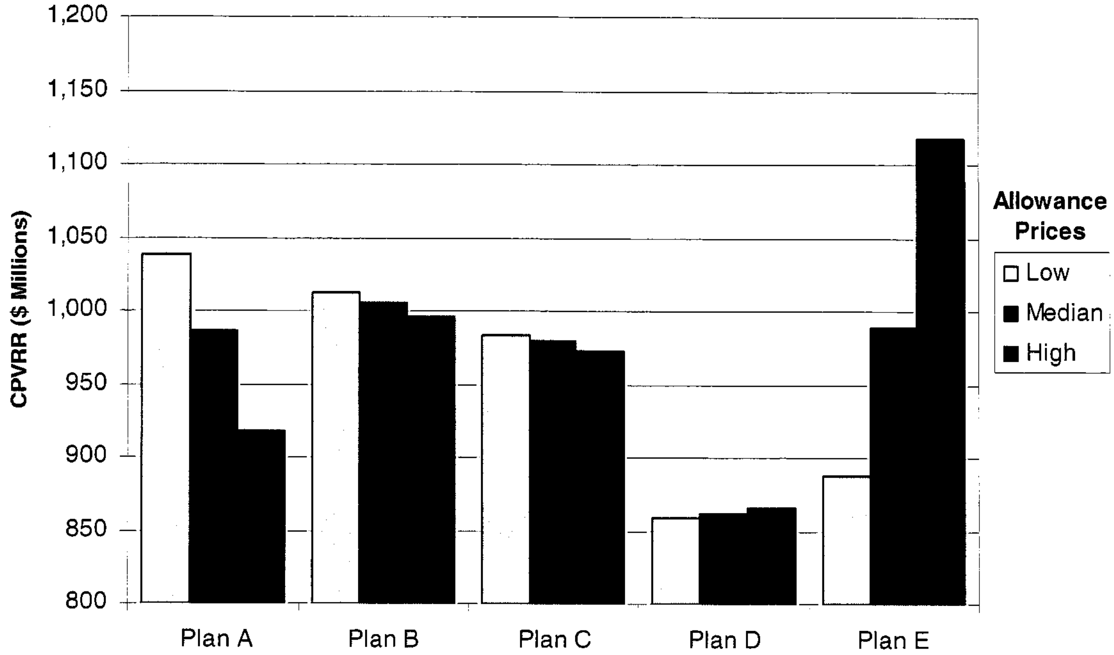
Sensitivity Analyses

Perhaps the two of the greatest sources of uncertainty in developing cost-effective compliance plans are the future prices of allowances (as discussed in Chapter 9) and the capital cost of emission control equipment. Therefore, analyses were conducted to examine the impacts on the cost of compliance due to higher or lower allowance prices and higher capital costs (only *higher* capital costs are examined because increases in the costs of labor and materials make higher capital costs more probable than lower capital costs).

Allowance Price Uncertainty

As discussed in Chapter 9, SO_2 and NOx allowance prices are volatile and the forecast of allowance prices is clouded by uncertainty. Because a couple of the alternative plans developed rely on the purchase of allowances and the economics of others are impacted through the possible sale of allowances, the plans must be evaluated over a range of allowance prices (see Figures 9-4 and 9-7). Figure 12-9 presents the CPVRR of the alternative plans assuming low and high allowance prices, in addition to the results assuming median prices that are shown in Figure 12-8. The figure shows that over the wide range of allowance prices, Plan D is always the lowest cost plan. When allowance sales are included, the cost of Plans A, B, and C decrease under high allowance prices (compared to median prices) and increase if allowance prices are low. The costs associated with Plan E are highly variable when exposed to low and high allowance prices. This is expected as Plan E relies on significant allowance purchases (refer to Figure 12-5). Plan D, on the other hand, is impacted to only a small degree by allowance prices.

Figure 12-9. Impact of Allowance Price Uncertainty

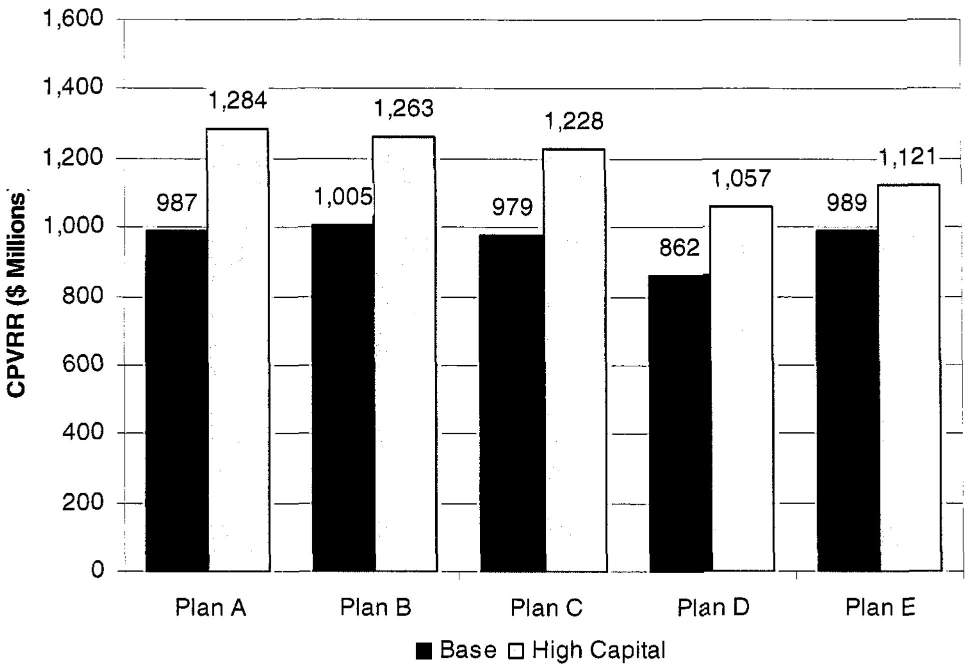


Capital Cost Uncertainty

The scrubber, LNB, and SCR cost estimates that have been used in the analyses discussed in this chapter are preliminary, and are not based on site-specific engineering for the PEF units. As discussed in Chapter 4, the cost estimates should be considered as being in the range of +/- 25 percent. Therefore, an analysis was performed to examine the impact on the CPVRR of capital costs being 25 percent higher than expected.

Figure 12-10 shows the impact on the cost of the plans if capital costs are 25 percent higher than expected. The figure shows the CPVRR of the plans compared to the costs under the base assumptions (also shown in Figure 12-8). As seen in the figure, Plan D remains the lowest cost plan among the alternatives. As would be expected, all the plans increase in cost. Plan A increases the most compared to the base assumption, simply because controls are installed on all of the Crystal River units in that plan. Likewise, Plan E, which relies on significant allowance purchases for compliance and has the lowest amount of capital expenditures of the plans, has the smallest increase in costs.

Figure 12-10. Impact of Higher Capital Costs on CPVRR



Qualitative Assessment of Plans

The quantitative evaluation provided above primarily addresses parts of three of the four decision criteria discussed in Chapter 1: meeting environmental requirements, managing risks, and controlling costs. This section will provide a qualitative assessment of the plans in terms of providing flexibility as well as some potential uncertainties not considered in the quantitative assessment.

As noted in the Plan Development section, Plan A is the only plan that complies with CAIR, CAMR, and the BART requirements of CAVR without purchasing allowances and without assuming BART controls will not be required for PEF units. Plan A does not provide much flexibility because emission controls are added to all four units at Crystal River as soon as possible, making it difficult to change direction based on new information. For example, if allowance prices turn out to be low, the Company will not be able to take advantage of the lower cost compliance method. Likewise, the overall cost reductions that might be anticipated by selling the allowances created by installing more controls than necessary will not be realized if allowance prices are low.

Both Plans B and C comply with CAIR without the need for buying allowances (except for NOx in the first couple of years) and they comply with CAMR. In addition to being the lower cost of the two plans, Plan C is preferable to Plan B because it calls for adding controls to Crystal River Unit 1, which allows PEF to install controls on Unit 2 in later years, if necessary. However, the addition of controls on Unit 1 also presents a disadvantage because Unit 1 is the smallest and oldest coal unit on PEF's system. Thus, Plans B and C are more flexible than Plan A in that they do not install controls on all Crystal River units right away. The FGDs installed on Crystal River

Units 1 and 2 are delayed until 2014 or 2015, which would give PEF time to observe allowance markets and assess any new technologies, especially mercury controls, developed in the interim.

Plan D achieves compliance by installing emission controls on PEF's two largest coal units (as well as NOx controls on the Anclote units). Because Crystal River Units 4 and 5 are also the newest coal units on the system, there should be less uncertainty in the cost to install the equipment on the units. It also will be easier to install controls on Units 4 and 5 because there are fewer physical obstacles around which to design and construct the control equipment. Plan D also provides flexibility. Because SO_2 and NOx emissions are below or near the amount of allowance PEF is to receive through 2014 (or beyond in the case of SO_2), this provides time for resolution of allowance market uncertainties. If allowance prices and the projection of future allowance prices increase, PEF has the ability to add controls to Crystal River Units 1 and 2 at a later date. Plan D also allows time for mercury control technologies to advance.

Plan E ensures compliance with CAVR because it calls for emission reduction measures on all three of PEF's units subject to BART. Because Crystal River Units 1 and 2 are the smallest coal-fired steam units on the system, the emission reductions are not enough to reduce PEF's emissions below the number of allowances held. As a result, Plan E requires significant allowance purchases to comply with CAIR. Plan E's reliance on allowance purchases provides flexibility to adapt to possible future changes. However, the additional flexibility comes at a significant increase in risk due to uncertainty in allowance prices. In PEF's judgment, the additional risk exposure is not worth the potential benefits.

Conclusions and Selected Plan

Plan D is the preferable plan from a number of perspectives and it meets all of the objectives set out in Chapter 1. It strikes a good balance between reducing emissions, by adding controls to the largest and newest coal units on the PEF system, and making use of the allowance markets to comply with CAIR. The plan complies with CAMR by reducing mercury emissions through the synergistic effect of wet scrubber and SCRs on Crystal River Units 4 and 5. Emissions are reduced greater than required in the early years, and these early reductions are banked for use later in time. To reduce mercury emissions further and remain in compliance through 2025, activated carbon injection controls are added to Crystal River Unit 2 prior to 2018.

Plan D provides flexibility by making use of allowance markets to account for a small portion of reductions required by CAIR. Because of the controls added for Plan D, PEF would need to purchase a minimal number of allowances through 2014. This should provide time for the allowance markets to stabilize, or for at least some of the uncertainties to be resolved. Should it appear that allowance prices are going to be high after 2014, Plan D provides PEF with the ability to add controls to additional Crystal River units at a future date, possibly taking advantage of any technology improvements that may be made. Likewise, should PEF experience higher load growth than expected, or if plans for future baseload units change, PEF could add controls on Crystal River Units 1 and 2, if necessary. Thus, Plan D enables PEF to manage its risks better than the other plans developed.

As seen in the quantitative evaluation of the plans, Plan D is the least cost plan under the base assumptions and also when considering allowance price and capital cost uncertainties. Thus, Plan

D is the most cost-effective alternative and is the compliance plan that Progress Energy Florida intends to pursue.