BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of coal costs for Progress Energy Florida's Crystal River Units 4 and 5 for 2006 and 2007

Docket No. 070703-EI

Submitted for Filing: March 16, 2009

REBUTTAL TESTIMONY OF JENNIFER STENGER ON BEHALF OF PROGRESS ENERGY FLORIDA

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REBUTTAL TESTIMONY OF

JENNIFER STENGER

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

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

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

A. I am employed by Progress Energy Florida, Inc. ("PEF") as a Lead Technical Project Management Specialist in the Power Operations Group.

Q. What are your responsibilities in that position?

A. My position resides in Strategic Engineering under the Power Operations Group and I am responsible for assessing impacts to PEF's Power Generation fleet for significant strategic initiatives and industry challenges. These initiatives range from evaluating impacts to our fleet from major regulatory or legislative activities such as the Clean Air Interstate Rule (CAIR), Greenhouse Gas and the Florida Renewable Portfolio Standards to leading a task force to review fuel flexibility issues for our generating units.

Q. Describe your education and background.

A. I have a Bachelors degree in Civil Engineering from the Georgia Institute of Technology and a Masters in Business Administration (MBA) from the University of South Florida. I am also a licensed engineer in the State of Florida and have been since 1997. I have been employed by PEF (previously Florida Power Corporation) since 1992, and while with the company, I have worked in the Environmental, Demand-Side Management and Power Operations departments in various program management roles.

II. PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the process that PEF uses when it considers burning a new type of coal in Crystal River Units 4 and 5 ("CR4" and "CR5"). PEF's operational obligations at the plant require a demonstration of performance impacts of any new coal so that we can evaluate those impacts and make an educated decision about the use of new coal at our plants. Typically, this means that predictive modeling, studies, and test burns need to be conducted. I will demonstrate that the Company's methodology and decisions as they would relate to the coal testing for CR4 and CR5 for 2006 and 2007 coal burns are consistent with the Commission's prior finding of reasonableness and prudency for this process in Docket 060658-EI.

This Commission previously heard testimony surrounding PEF's test burns and analysis of Powder River Basin ("PRB") coal at CR4 and CR5. I will explain how this PRB coal is very different from the Spring Creek Coal, as well as the Indonesian coal that Mr. Putman uses in his testimony. I will discuss these differences in detail and explain how coal characteristics can impact and effect unit performance.

I will also discuss the approximate amount of time that it takes to appropriately test coal that has not been previously tested in the units and why these step-by-step procedures are necessary in making informed and prudent coal testing decisions that are in the best interests of the Company's customers in the short and long term.

As part of this process, I will also address how PEF determines whether capital upgrades are necessary to burn coals that have not been previously tested and the timing of upgrade installations, as well as the time needed to make any needed adjustments to environmental permits for the plants.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits that I have prepared or that were prepared under my supervision and control:

- Exhibit No. ___ (JS-1), Spring Creek coal specification sheets and information;
- Exhibit No. ___ (JS-2), PT Adaro Indonesian coal specification sheets and information;
- Exhibit No. ___ (JS-3), PT Kideco Indonesian coal specification sheets and information;
- Exhibit No. ___ (JS-4), Peabody Coaltrade Wyoming 8800 Btu PRB coal specification sheets and information;
- Exhibit No. ___ (JS-5), Peabody Coaltrade Wyoming 8585 Btu PRB coal specification sheets and information;
- Exhibit No. ___ (JS-6), Composite Exhibit of Documents Referenced in Stenger Rebuttal Testimony regarding portions of FPSC Order No. PSC-07-0816-FOF-EI in Docket No. 060658-EI; and referenced portions of testimony previously filed in Docket 060658-EI;
- Exhibit No. ___ (JS-7), WE Energy coal explosion material;

- Exhibit No. ___ (JS-8), Capital costs of certain equipment if Spring Creek coal or Indonesian coal were burned.
- Exhibit No. ___ (JS-9), Coal Quality Comparisons
- Exhibit No. ___ (JS-10), ASTM Coal Ranking Table
- Exhibit No. ___ (JS-11), Evaluation Timeline for Spring Creek Coal
- Exhibit No. ___ (JS-12), Evaluation Timeline for Indonesian Coals
- Exhibit No. ___ (JS-13), Electrostatic Precipitator (ESP) Diagram
- Exhibit No. ___ (JS-14), B&W Unit Diagram and example photos

All of these exhibits are true and correct to the best of my knowledge.

Q. Please summarize your testimony.

A. Crystal River Units 4 & 5 are baseload generation units that have historically produced high levels of gross energy production. These are must-run units that provide low cost power on a first-call basis. In Order No. PSC-07-0816-FOF-EI, issued on October 10, 2007 in Docket No. 060658-EI, at page 27, the Commission recognized the importance of these generation units by stating that: "We believe the continuing reliable operation of CR4 and CR5 is of paramount importance."

Although the original boiler and turbine design for CR4 and CR5 was 665 megawatts (MW) gross energy production at full capacity, PEF has operated the units at overpressure achieving between a gross 750 megawatts (MW) and 770 MW of generation capacity and energy to customers. The design and construction of these units, particularly the large boiler design, and the high quality, high Btu bituminous coal historically used by PEF have allowed PEF to achieve these levels of gross energy production. PEF customers have received the benefit of the increased output of these units.

As this Commission rightfully recognized in Docket 060658-EI, changes in the quality and type of coals for CR4 and CR5 can impact the performance of the units as well as their safe and efficient operations. Before coals of a different type or coals with different qualities are burned, PEF carefully evaluates those coals to determine the impact they will have on the operation and production of the units. Without previous burning experience or knowledge of coal characteristics, PEF places the units at risk of an outage, a de-rate, an environmental permit violation, or other operational difficulties. It is PEF's responsibility to safely and efficiently operate the units to produce full capacity to meet customer load. The Commission agreed in Order No. PSC-07-0816-FOF-EI, page 29 that the performance of CR4 and CR5 must not be compromised. Any action that causes a reduction to the generation output of CR4 and CR5 would necessarily be replaced by generation that is more costly.

In Docket 060658-EI, the Commission heard testimony from PEF witnesses concerning PEF's testing process. The Commission considered and accepted PEF's process to test PRB coal, a coal that it had no previous experience with. The accepted process included predictive "paper tests," test burns of several days, short term test burns spanning a few months, and long-term test burns that may span several months to a year, to fully examine the operational, safety and performance of using PRB coal. The Commission also recognized that analysis had to be done during the course of test burns, and such analysis may include various degrees of engineering studies (Order No. PSC-07-0816-FOF-EI, pages 30-31).

In addition to operational issues, this Commission recognized that PEF must also consider safety issues, environmental impacts, and cost issues associated with burning coals that PEF has not previously tested. PEF may have to expend time training employees on the handling of coals not previously tested, implement necessary maintenance to safely and efficiently handle the previously untested coal, and secure tests to analyze the effects of the coal on the units (Order No. PSC-07-0816-FOF-EI, pages 28-29).

In the 060658 Docket, this Commission found that capital upgrades may also be necessary to safely and efficiently handle the coal at the plant site either before or after tests can be performed (Order No. PSC-07-0816-FOF-EI, pages 35 and 38). In addition, capital upgrades may be necessary to ensure that the coals can be burned safely and efficiently in the units. There are many concerns to be considered before switching to coals that have not been previously tested. This is nothing foreign. It is merely the same process that PEF has utilized in the past and continues to perform to ensure reliable, safe, and efficient operations at CR4 and CR5.

The Commission also recognized on page 19 of the order that as you learn more about coal during the test burns, an amendment to the Title V permit may be necessary, a process that would take about 14 months for the PRB coals that the Commission reviewed in that case. (Order No. PSC-07-0816-FOF-EI, page 37). Similarly, additional amendments may be necessary for Spring Creek coal and Indonesian coal.

In summary, this Commission has already found that there are many concerns that PEF must consider when switching to alternate coal sources. All of the processes to evaluate coals and implement upgrades, install equipment, amend permits, and train employees involve a substantial amount of time and money. The Commission recognized this fact on page 37 of its 2007 order stating that: "We find that PEF would have needed time to prepare itself to burn PRB… Had PEF taken the appropriate actions in 2001, it would have been ready to burn PRB by 2003."

III. OPERATIONAL CONCERNS

Q. Why is it important to analyze coal that has not been previously tested at CR Units 4 and 5?

A. In FPSC Docket 060658-EI, PEF witness Wayne Toms presented testimony concerning the operations at CR4 and CR5. He explained that certain equipment in the plants, such as the boiler, pulverizer, and electrostatic precipitators are especially sensitive to changes in coal quality and types. It is critical for PEF to know how the plants will react to new types and qualities of coal on a short and long-term basis because new coal products may cause de-rates or forced outages in the units. PEF employs steps and methods, including test burns, that allow PEF to identify operational, safety, environmental, and performance issues prior to making full-scale commitments to switch to or use a new coal product. Based on Mr. Toms' actual operating experience, the Commission understood the risks associated with combusting untested coals and found Wayne Toms' testimony to be persuasive (Order No. PSC-07-0816-FOF-EI, page 30).

IV. COAL TESTING

Q. What is the purpose of coal testing?

A. Coal bids and contracts contain summarized information concerning coal make-up. Coal suppliers provide coal specifications sheets that generally describe "typical" characteristics of the coal that is being offered. In Docket 060658, Witness Wayne Toms explains the importance of actual test burns since the actual coal provided to the site can vary from what the vendor lists in a bid specification as "typical" characteristics. When PEF identifies characteristics on these specification sheets that differ from the coal it is used to burning, it is necessary to evaluate coal from an operations, environmental, and safety perspective because we want to know how the coal varies from our known coal and historical experience. Naturally, we want to understand how the coal will affect the maintenance, operation, and the production of energy from the units. As Mr. Heller states in his testimony, it is important to compare coals of very different characteristics to understand how they affect boiler operations, unit output, and safety concerns. The Commission heard testimony and recognized the significance of coal testing in its prior order (Order No. PSC-07-0816-FOF-EI, page 30).

Q. Routinely, what steps are involved in testing coal that PEF has not previously tested?

A. PEF initially starts with predictive modeling through a "paper test" that utilizes applications such as the Vista Computer Model widely used in the electric power industry, industry data and information, supplied coal specifications, and any other relevant data available. The Commission heard testimony on and accepted this type of predictive modeling in Docket 060658 (Order No. PSC-07-0816-FOF-EI, page 20-22). There are several levels and degrees of predictive modeling available that vary depending on the type and characteristics of the new coal being considered. If, for example, PEF is considering mixing a high quality bituminous coal with a lower Btu bituminous coal that has virtually identical specifications, PEF would likely employ a less intensive predictive modeling process when compared to coals that vary greatly. When comparing coals that are very different, the predictive modeling process may also include summary, intermediate, or detailed engineering studies not unlike the PRB coal studies that the Commission examined in Docket 060658 (Order No. PSC-07-0816-FOF-EI, page 28). In addition, when investigating coals that have characteristics that are significantly different from ones that have been previously fired, benchmarking is usually conducted with other utilities that either currently burn the fuel in question, have previously tested the fuel, or have completed a fuel switch to the type of coal in question. This information can provide a different perspective from what the predictive model might indicate. If the coal passes the paper test, and if the risks are considered manageable based on other utility experience, then a decision is made whether it would be beneficial to conduct an engineering study which would research the potential issues based on our specific unit configuration. Following this study, if conducted, a short test burn of a few days would follow. I discuss this process in detail later in my testimony. If no immediate operational, environmental, or safety concerns are identified during these few days, PEF would follow this test with a short-term test spanning a few months to identify any problems that would not present themselves in a very short test. The last test to determine unit performance and efficiency over a sustained basis would involve a long-term test burn lasting several months to a year. This process is also discussed in detail later in my testimony and in the prior case that this Commission considered.

Q. You are aware that PEF previously tested a blend of PRB coal in April 2004 and in May 2006, correct?

A. Yes, as noted in previous testimony and documented by the Commission on page 28 of the October 17, 2007 Order, PEF procured 8,800 Btu PRB coal from Peabody Coaltrade in 2004 to conduct the initial PRB coal test burn. This coal originated from the Peabody North Antelope Rochelle Mine near Gillette, Wyoming. PEF attempted to test a 15/85 blend of PRB coal/bituminous coal.

In 2006 following an analysis by Sargent & Lundy, PEF completed a second short-term test burn. A shipment of 8,585 Btu PRB coal was blended offsite with bituminous coal. This PRB coal originated from the Peabody Black Thunder Mine, about 44 miles south of Gillette, Wyoming. The commission also recognized this approximate 20/80 blend of PRB coal/bituminous coal test burn on page 28 of the October 17, 2007 Order.

For the purpose of my testimony, I assume that by 2004, PEF had completed all its testing for PRB coal, and completed all the capital upgrades for PRB coal that the Commission recognized in Order 07-0816, and I assume that PEF had an environmental permit in place that would allow PEF to burn up to a 20% blend of PRB coal.

Q. OPC Witness, David Putman, alleges that in 2006 PEF should have burned Spring Creek PRB Coal offered by Kennecott Energy in May 2004. Had PEF previously tested the Spring Creek PRB Coal offered by Kennecott Energy in May 2004?

A. No.

Q. Is the Spring Creek Sub-bituminous Coal that OPC witness David Putman refers to in his testimony different from the 8,800 Btu and 8,585 Btu PRB coals that PEF tested in the past?

A. Yes, the Spring Creek Coal originates from southern Montana. The properties of coal originating in this region are much different than the PRB coal that the Commission considered in Docket 060658 and that PEF previously tested. Those differences are described below, and the Spring Creek Coal specifications are attached as Exhibit No. __ (JS-1). In addition, a comparison of the basic coal quality parameters between the fuels is attached as Exhibit No. ___ (JS-9).

Spring Creek coal has several coal quality composition factors which are different than the PRB coal previously tested. Some of these include differences in iron and calcium content, but most noticeably is the significant increase in sodium content in Spring Creek coal of over 400%. A small increase in sodium content in coal, much less an increase of this magnitude, has the potential for significant operational issues due to slagging and fouling. The sodium will volatilize in the flame and then recondense on the alumina silicate particles causing a molten outer layer on the ash particle. This is due to sodium's lower melting temperature as compared to other ash particles and its propensity to act as a binding agent, or glue, with those ash particles.

The Base to Acid ratio (B/A) is also indicative of an increased potential for buildup and is defined as the ratio of base compounds in the ash (iron, calcium, magnesium, potassium and sodium oxides) to the acid compounds in the ash (silica, aluminum and small amounts of titanium). The Base compounds, of which sodium is one, are the main contributors to the formation of slagging and fouling formation and deposits.

The B/A ratio of Spring Creek coal is 50% more than that of the PRB coal tested previously.

Q. **Is it fair for Mr. Putman to assume that a 20% blend of Spring Creek and CAPP coals would yield the same operational, environmental, and safety result as a 20% blend of Black Thunder Mine PRB and CAPP coal that PEF previously tested?**

A. No, as I stated previously, these coals are very different and may behave very differently, even in a blend. In some instances, a blended coal may cause even more operational issues. For example, for coals with a significant percentage of base compounds (sodium, calcium or iron), the binding nature of these compounds can generate even more buildup as they "trap" other ash particles that would traditionally flow through the gas stream without sticking. This is similar to a wet ball rolling in dry sand and the sand attaching itself to the ball. Also, even with off-site blending, there is no "guarantee" that the blended coal will portray homogeneous properties throughout the shipment and these fluctuations could lead to additional operational, safety, environmental or performance issues that would need to be tested. As the Commission previously recognized, there is no comparison between hypothetical presumptions about coal and actual, tested operational history (Order No. PSC-07-0816-FOF-EI, pages 29-30).

Q. **Is the PT Adaro Indonesian Coal that OPC witness David Putman refers to in his testimony different from the 8,800 Btu and 8,585 Btu PRB coals that PEF tested in the past?**

A. Yes, this coal originates from the Tutupan mine located in Indonesia's South Kalimantan Province in Asia. Coal originating in this region of the world is much different than the Wyoming PRB coal that PEF previously tested. Those differences are described below and the specifications for the PT Adaro Indonesian coal are attached as Exhibit No. __ (JS-2). In addition, a comparison of the basic coal quality parameters between the fuels is attached as Exhibit No. ___ (JS-9).

The PT Adaro Indonesian coal has several coal quality composition factors which are different than the PRB coal previously tested. Some of these include differences in iron, calcium and sodium content as well as ash content. Similar to the Spring Creek coal, the Base to Acid ratio for the PT Adaro coal is 100% higher than for the PRB we previously tested.

The increased oxygen content of the PT Adaro coal would also prompt additional investigation as oxygen content is inversely proportional to the self-heating temperature (SHT) for a coal. As the oxygen in the coal goes up, the self-heating temperature comes down which increases the probability for spontaneous ignition which could lead to fires and explosions.

Another significant difference between the PT Adaro coal and the PRB coal tested previously is its ultra-low sulfur content level. While low sulfur content may be advantageous for a reduction in SO_2 emissions, it can pose significant negative impacts to the performance of the electrostatic precipitator (ESP), which is used to control opacity and particulate matter emissions. As resistivity goes up, the ESP's efficiency goes down.

So, just like Mr. Putman's assumptions with Spring Creek Coal, it is wrong for him to presume that a 20% blend of PT Adaro Indonesian Coal would act the same as a blend of the PRB coal that the Commission considered in Docket 060658.

Q. Is the PT Kideco Indonesian Coal that OPC witness David Putman refers to in his testimony different from the 8,800 Btu and 8,585 Btu PRB coals that PEF tested in the past?

A. Yes, this coal originates from the Batukajang mine located in Indonesia's East Kalimantan Province in Asia. Coal originating in this region of the world is much different than the Wyoming PRB coal that PEF previously tested. Those differences are described below and the specifications for the PT Kideco Indonesian coal are attached as Exhibit No. __ (JS-3).

Some of the differences are similar to the ones associated with the PT Adaro coal such as ultra-low sulfur levels, high oxygen content, low self-heating temperature and a high base to acid ratio. However, the PT Kideco coal also exhibits a much higher iron content, higher ash content, and lower Btu content as illustrated in Exhibit No. __ (JS-9) attached.

Just like Mr. Putman's assumptions with Spring Creek Coal and PT Adaro Indonesian Coal, it is wrong for him to presume that a 20% blend of PT Kideco Indonesian Coal would act the same as a blend of the PRB coal that the Commission considered in Docket 060658.

A. POWDER RIVER BASIN COAL

Q. Please describe the coal qualities of the PRB coal that the Commission considered in Docket 060658.

A. As witness Rod Hatt stated on page 8 of his prefiled testimony filed in PEF's earlier Docket 060658-EI, the Wyoming PRB coal that the Commission reviewed has lower Btu content, high volatility, less stability causing dustiness and increased flammability, high moisture content and the susceptibility to hold moisture, higher calcium and sodium, and lower sulfur properties. Mr. Hatt provided a coal quality comparison attached as Exhibit No. __(RH-5) to his testimony in that case.

Q. Did PEF perform a paper test to analyze this Wyoming PRB coal?

A. Yes, in 2004 PEF did predictive modeling on an 80/20 blend of PRB/CAPP coal as previously indicated in Jamie Heller's testimony filed January 16, 2007 in Docket 060658-EI. As Mr. Heller indicated, PEF used the Coal Quality Impact Model (CQIM) to determine the impact of variations in coal quality. The model was widely used for performing such analyses. As this Commission is aware, PEF also retained the service of Sargent and Lundy to evaluate the burning of various blends of PRB and Illinois coal at Crystal River Units 4 and 5. This study was produced and attached as Exhibit No. SAW-14 to the testimony of Sasha Weintraub in Docket 060658-EI. The study provided a first cut evaluation to determine if PRB coal would provide an economic benefit for PEF while focusing on the two major areas of safety and performance (Order No. PSC-07-0816-FOF-EI, pages 28, 31). As the Commission also noted on page 31 of this order, PEF preceded the 2005 Sargent and Lundy assessment with in-house predictive modeling performed by PEF's Strategic Engineering Group to better understand the impact of burning PRB coal at Crystal River Units 4 and 5. Reports generated by PEF's Strategic Engineering Group from May 2005 through September 2005 were produced and attached to the testimony of Sasha Weintraub as Exhibit Nos. SAW-8 through SAW-13, and SAW-15 in Docket 060658-EI. The Commission heard testimony and recognized that PEF used the same process to evaluate coals from 1996 through 2005 (Order No. PSC-07-0816-FOF-EI, page 30). Because PEF performed a "paper test" of the Wyoming coal in 2004, PEF did not repeat this test in 2006 because it was familiar with the coal characteristics.

Q. Did the paper study process provide some information as to how the coal would perform in the units?

A. Yes

Q. Were there other considerations that were evaluated at this point?

A. Yes. We looked at other utilities that burned this type of coal and what types of units were burning the coal. If the unit was not originally designed to burn that type of coal, we looked at the upgrades that the utility installed to burn the coal being introduced.

Q. What else did PEF have to do prior to initiating a test burn?

A. PEF submitted an application to the FDEP on March 3, 2006 requesting permission to conduct a 2006 test burn of sub-bituminous/bituminous coal.

Q. Do you know the time involved in that process?

A. Yes, PEF retained Golder and Associates in October 2005 to assist with the permit application. The final permit allowing PEF to conduct the test burn was issued on April 26, 2006.

Q. A decision was made to proceed with a short-term test burn, correct?

A. Yes, the 3-day test burn was then scheduled for and conducted in May 2006.

Q. What was involved in scheduling a short-term test burn?

A. In addition to working with the Fuels Department to purchase the test burn fuel blend and determine delivery dates, there was coordination required with numerous other stakeholders including the Energy Control Center (ECC) to specify the test days and loads needed, the Environmental Department to schedule the air testing team to conduct the required emissions testing, Plant Operations to discuss the potential operational impacts expected from this fuel blend and what to look for, and the Fuel Handling Group to discuss the plan for minimizing the safety risk that comes with handling the unstable PRB coal and to address procedures for enhanced housekeeping required for the test burn.

Q. Was a short-term test burn was conducted?

A. Yes. The Commission has previously heard testimony concerning PEF's 2004 short-term test burn and the Commission addressed the results of this test burn on page 28 of its October 10, 2007 Order (Order No. PSC-07-0816-FOF-EI, page 28). Coal specification sheets for the PRB coal tested in 2004 are attached as Exhibit No. ____ (JS-4) to my testimony. The Commission also heard testimony concerning the May 2006 test burn of the Wyoming PRB coal and also recognized the outcome of the test burn on page 28 of the Order. Coal specification sheets for the PRB coal tested in 2006 are attached as Exhibit No. ____ (JS-5) to my testimony.

Q. What were the results of the short-term test burns?

A. There were no substantial issues with the limited test burn. However, the test burn report which was attached as Exhibit No. __(SAW-16) to Sasha Weintraub's testimony in Docket 060658, acknowledges that a longer test burn of at least several weeks in duration at both CR4 and CR5 was necessary for an analysis of the impacts on boiler operations and fuel handling systems from the use of a PRB blended coal product. The recommendations included additional steps in the evaluation of the use of PRB coals at CR4 and CR5, including obtaining a permit modification to include sub-bituminous coal use, implementing necessary improvements to CR4 and CR5 prior to a tandem burn at CR4 and CR5, and conducting a longer test burn on both units with a sub-bituminous and bituminous coal blend.

Q. Is safety an important consideration in the test burn process?

A. Absolutely. It is very important to consider all handling conditions of various coals and the safety hazards involved in combusting coal. I have attached as Exhibit No. __ (JS-7), a news article regarding a recent WE Energy explosion that injured 5 contractors resulting from extremely volatile sub-bituminous coal which demonstrates the importance of taking the time needed to make sure all safety considerations are addressed prior to burning more volatile coals. The safety of our employees and contractors is and has been PEF's number one concern. On page 30 of Order No. PSC-07-0816-FOF-EI, the Commission recognized this in stating, "Issues of safety and cost are relevant to PEF's analysis."

Q. Did PEF determine whether capital upgrades or O&M improvements would be necessary to begin using a blend of Wyoming PRB coal?

A. The specific break-down of the cost estimates for the capital upgrades and increased operation and maintenance expenses were provided in Exhibit No. __(RH-8) to Rod Hatt's testimony in Docket 060658.

Q. If the results of a short term test burn would have been favorable at the time, would you proceed to a longer-term test burn?

A. Yes, from an operational, safety, and environmental perspective, this would have been the next step if PEF had no issues with initial test burns. As I discuss later in my testimony, the next series of burns would have consisted of burns spanning several months to a year or more so PEF could identify any problems that, by their nature, do not manifest on shorter duration burns.

Q. What amount of time does it entail to organize and conduct a longer-term test burn?

A. As I discuss later in my testimony, the process to organize this longer test burn can take between 3 to 12 months or sometimes longer, depending on a number of factors including any permits that need to be procured, the lead time needed for certain capital equipment and timing with Spring or Fall outages for installations, completing any integration or modifications with the operator's distributed controls system (DCS) or other equipment controls, development of any testing protocols, setting up an automated process to record trending where applicable, and training of operation's employees on new equipment or procedures. Once these items have been set up, then the actual longer-term test burn of around 3 months can begin. In some instances, it may be necessary to conduct an extended test burn of 6 to 12 months to determine long-term maintenance increases and impacts to unit reliability before making a final assessment.

B. KENNECOTT SPRING CREEK COAL

Q. Please describe the coal qualities of Spring Creek coal.

A. Spring Creek coal is classified as a low rank Class C sub-bituminous coal. Please refer to Exhibit No. ___ (JS-10) which shows the ASTM coal ranking classification breakdown.

This coal, similar to other sub-bituminous coals, has very high moisture content, a low Btu value, a high oxygen and calcium content, a high propensity to gain and hold additional moisture due to its porous "sponge-like" structure and decomposes easily creating significant amount of coal fines or dust over time from basic handling.

Unlike some other sub-bituminous coals, Spring Creek coal has very high sodium content. As mentioned earlier in my testimony, the sodium content in Spring Creek coal is over 400% more than the PRB previously tested and over 620% more that Eastern bituminous. An increase in the sodium content of coal of this magnitude has the potential for significant operational issues due to slagging and fouling which could lead to de-rates and forced outages for boiler and convection pass cleaning. This coal has a high Base to Acid ratio (B/A) which is also indicative of an increased potential for buildup from combustion.

Q. Has PEF previously tested Spring Creek coal?

A. No.

Q. What impact might these differences have on CR Units 4 and 5?

A. The increased sodium content in Spring Creek coal, especially of this magnitude, will have the potential for significant operational issues due to slagging and fouling formation. The sodium will volatilize in the flame and then recondense on the alumina silicate particles causing a molten outer layer on the ash particle and will tend to act as a binding agent, or glue, with other ash particles.

Higher slagging and fouling coals could cause de-rates and additional time offline for boiler cleaning. While slagging and fouling are similar, where they occur in the combustion system is different. Slagging, which includes clinker formation, occurs in the furnace area of the boiler, while fouling generally occurs in the convection pass which starts at the planten region of the superheaters (see Exhibit No. __ (JS-14) which shows a diagram of these locations. In addition, some examples of different types of slagging and fouling are also included in this exhibit.

In addition, soot blowers and other equipment necessary to control slagging and fouling, such as water cannons, would need to work harder and require more maintenance because of this coal. This would increase the wear and tear on this equipment and increase the maintenance costs. Soot blowers blast high velocities of steam into the boiler in order to clean the slag buildup, however, this can lead to erosion of the boiler tubes. Therefore an increase in the use of soot blowers could increase the rate of this erosion. Likewise, installing water cannons that may be needed for significant slag buildup may cause quench cracking of the tubes due to the thermal shock. These issues and the increased use of this equipment could then lead to de-rates and outages due to tube leaks.

Also, as witness Rod Hatt stated on page 12 of his previous testimony filed in Docket 060658-EI, sub-bituminous coals are younger and less stable. They will tend to lose their Btu value quickly once removed from the mine and that most suppliers will measure the Btu value at the mine, which will most likely not be representative of the Btu value of the coal once it reaches the site. This lower Btu value could impact the unit's performance and ability to reach over pressure and achieve the top megawatt loads expected.

Q. Do the characteristics of Spring Creek Coal differ enough from the Wyoming PRB coal that PEF previously tested to merit a paper test burn of the coal?

A. Definitely. Please refer to Exhibit No. ___ (JS-11) which shows the timelines associated with the various testing and evaluation scenarios that would be employed when researching whether to move forward with burning Spring Creek coal. I will provide additional detail on each of the aspects further in my testimony.

Q. If PEF were to consider burning Spring Creek Coal, would PEF employ the same process that it has in the past to determine whether this coal could be successfully burned at CR Units 4 and 5?

A. Yes, with the high sodium content, high calcium content, low Btu value and high moisture percentage in this fuel, there is a potential for issues to arise while burning this fuel, even in a blend, with respect to operations, fuel handling, safety or environmental performance. As such, the testing scenario for Spring Creek coal would most likely fall under either the "Medium Fuel Case" or the "High Fuel Case" as reflected in Exhibit No. JS-11 to my testimony, depending on the results from the paper test and any benchmarking information gathered from other users burning this fuel.

Q. Would you begin with a "paper test" to analyze the Spring Creek Coal?

A. Yes, this would be the first step with evaluating any new fuel into our system.

Q. Would the paper study provide information as to how the coal would perform in the units?

A. It will provide "predictive" indications of how Spring Creek coal or a Spring Creek/ CAPP coal blend might perform in the unit, however, as it is still just a model, and it would not "guarantee" any specific unit performance.

Q. Could you estimate the amount of time it would take to perform a paper study?

A. This could take between two to four weeks to run the model with the appropriate fuel specifications, analyze the results, and classify the potential risks that would need to be investigated further.

Q. Are there costs involved in the paper study?

A. Yes, these costs would mostly involve the labor and overhead for the engineer to perform the steps as listed above.

Q. Are there other considerations that you would evaluate at this point?

A. Yes. We would undertake a benchmarking effort where we look at other utilities that have burned this type of coal and what kind of units the coal is burned in. We would also determine what other types of coal the other units can successfully burn and whether they burn the fuel in question solely or in a blend. If they burn a blend, we would determine what blend ratios they are using. We would also ask what types of operational, safety, environmental or performance difficulties they experience while burning this type of fuel and any lessons learned through their experience. If the unit is not designed to burn that type of coal, we look at the upgrades those units have required to burn the coal being introduced.

While this benchmarking provides some useful insight into the types of issues that might be encountered, however, it is by no means a substitute for actual testing in our specific units.

Q. Can you estimate how long this would take?

A. Benchmarking can take from a couple of weeks to several months depending on the amount of information needed, and how obtainable it is to access the information needed. Once a utility and/or unit(s) are identified, it may take some digging to find a contact with which to correspond with, either through email or by phone. Establishing contacts is usually accomplished through networking at various industry conferences, such as Coal-GEN, or through industry user groups that our employees may be members of. Once a contact is identified and communication is established, we ascertain who might best be able to answer our questions. This could include numerous individuals from operations, maintenance, engineering, fuels, environmental, specific projects, etc. depending on the level of technical detail requested. The information gathering may take the form of sending them a list of questions for them to respond to or by setting up a conference call where many technical stakeholders can participate in an open forum manner. If possible, the same benchmarking approach is applied with more than one utility in order to get a varied perspective of the issues and see how different or similar they are at different plants.

In addition, if feasible, a plant field trip might be scheduled to see firsthand some of the potential issues that might be encountered with burning this type of fuel.

Q. Would there be a cost associated with performing this research?

A. For the most part, the information gathering costs would be associated with the labor and overhead for the time spent researching and coordinating any meetings and preparing summary reports. However, if a field trip is undertaken, then of course there would be trip related expenses.

Q. Are there other considerations?

A. Yes. If the paper test appears favorable, we must also consider PEF's environmental permits in place and determine whether the permit would allow for a short-term test burn or whether PEF would be required to submit an application to test this type of coal.

Q. Can you estimate how long it might take to review the environmental permits?

A. A review of the environmental permits might take two to three weeks depending on if a permit is required prior to the test burn. If so, an air construction permit would take between 3 to 6 months to obtain. While the actual time from application submittal to approval is about 2 months, based on the PRB test burn, time needs to be included for preparation of the application and in most instances, previous conversations with the agency would have occurred prior to the application submittal.

In some instances, a third party environmental firm may also be employed to assist with calculating the potential emissions, as those calculations can sometimes be fairly complex. These calculations may also be warranted if equipment needs to be installed prior to the 3-day test burn. Even if the subsequent calculations do not show an emission increase, they would still need to be performed to document that this was reviewed prior to moving forward with the test burn.

Q. If PEF were required to prepare and submit an environmental application to the FDEP to test Spring Creek coal, would there be a cost associated with preparing and submitting the application?

A. Yes, both internal costs and additional external costs if a third party environmental firm is needed to assist with the application's preparation as was the case for the PRB test burn.

Q. Besides obtaining a permit for the test burn, are there any other environmental considerations needed?

A. Yes. We would need to investigate how Spring Creek coal would impact the Clean Air Project for Units 4 and 5. This project includes the installation of a wet scrubber (FGD), a Selective Catalytic Reduction (SCR) system, and Low-NOx burners (LNB) on each of these units. As witness Michael Kennedy stated in his testimony in Docket 060658-EI, PEF had decided to add scrubbers to the units to comply with the regulations passed by EPA in early 2005, so these considerations would have been relevant to coal that PEF would burn in 2006 and 2007.

For example, Spring Creek coal is resistant to mercury removal through the use of a scrubber due to its low chlorine content and additional equipment is needed for mercury removal such as a baghouse. Thus, any economic analysis of Spring Creek Coal would need to include the additional equipment needed to comply with the new mercury rule. Additional impacts that would need to be investigated include how the "reducing environment" created by the use of Low-NOx burners impacts the already high slagging potential of Spring Creek coal. Under a reduced environment, the melting point of certain coal constituents, specifically sodium and calcium, is even lower and increases the slagging potential even further. We would also need to investigate the arsenic concentration of Spring Creek coal to determine its impact on SCR catalyst degradation.

All of these issues would be relevant to the overall determination of feasibility of Spring Creek coal.

Q. Is there other planning involved before a decision is made to move forward with a short-term test burn?

A. Yes, depending on the issues identified from the paper test and benchmarking, and their potential for impacting operations, fuel handling, safety or environmental compliance, and unit performance, a decision might be made to bring in a third party engineering firm to conduct a site and unit specific engineering study. This engineering study would involve reviewing the site and unit's current configuration and providing recommendations on new capital equipment or maintenance that might be needed in order to successfully burn the Spring Creek coal. The engineering report developed would show a breakdown of costs associated with a short-term test burn and capital expenses recommended for a longer-term test burn as well as any maintenance costs that need to be accounted for.

Q. Can you estimate the time involved to conduct an engineering study?

A. This could take anywhere from three to six months from beginning to end. Usually for an engineering study like this we would be required to prepare an RFP and submit to several vendors. Then we would need to review the proposals and award the contract before the actual site investigation begins. There would also be time spent coordinating the work efforts and site visits with the firm. Then the firm would perform their investigation, determine the design modifications needed, and prepare a report listing their recommendations.

Q. Can you estimate the cost associated with performing an engineering study with a third party firm?

A. I would estimate that these costs would be similar to the ones associated with the Sargent & Lundy study performed for PRB.

Q. Following the engineering study, if undertaken, is there any other planning involved before a final decision is made to move forward with a short-term test burn?

A. Yes, meetings would be held with various stakeholders including the Strategic Planning Group and Fossil Generation Group to get input on planned outages and maintenance issues that must be considered. In addition, in mid to late 2004, there was a lot of discussion about the development of a federal rule that would extend the cap and trade mechanism associated with the Acid Rain Program and the development of a new Mercury rule. The draft rules for the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) were published in the Federal Register in March 2005. However, internal discussions had occurred well before that with respect to what pollution control equipment might be needed to achieve compliance with these two rules. In 2004, we had determined that Crystal River Units 4 and 5 would need to install a wet scrubber (Flue Gas Desulfurization system – FGD) to limit SO_2 emissions along with a Selective Catalytic Reduction system (SCR) and Low-NOx Burners (LNB) to limit NOx emissions, so we would have had to consider all these factors as well in analyzing the potential use of Spring Creek coal.

Q. Can you estimate the time involved to conduct these meetings?

A. These additional meetings could have taken several weeks.

Q. Based on the paper test results, would you consider capital upgrades before conducting a 3-day short-term test burn?

A. Possibly, depending on the magnitude of the capital expense and the predicted success with burning the Spring Creek coal. However, for the most part, only minor modifications and/or maintenance items would be addressed in advance of a 3-day test burn. Typically, the company does not spend significant capital on equipment until the long-term viability of the fuel in question is investigated and confirmed.

Q. If capital upgrades were necessary before testing Spring Creek coal, can you estimate how long it would take to purchase and install those upgrades?

A. This could vary significantly and would be dependent on several factors such as if an RFP needs to be prepared and submitted, the lead time and availability of the equipment, and if the equipment needs an outage to install, and for how long.

Q. Would there be costs associated with those capital upgrades?

A. Refer to Exhibit No. ___ (JS-8) for the list estimated costs of capital additions that might be recommended.

Q. Based on the paper test results, would it be necessary to consider any equipment operations issues before conducting a 3-day short-term test burn?

A. Yes, all issues related to maintaining the unit's reliability and safety considerations would need to be addressed. A test protocol would also be developed for operations to record various operating parameters throughout the test. These could include such areas as slagging and fouling indications, fuel handling problems, pulverizer performance and speed, air heater plugging, temperature increases or decreases, differential pressure drops or increases, any alarms encountered, ESP performance, overall unit performance, and other related issues.

Q. Can you estimate how much time it would take to perform necessary equipment operations training and testing before proceeding with a short-term test burn?

A. This could take at least a couple of weeks depending on how many shifts need to be trained and the expected length of the training. If the information is fairly straightforward and only a limited amount of information needs to be covered, then it could potentially be combined with the daily safety briefing. However, if there are more extensive items that need to be covered, new equipment or controls to learn how to use, or additional maintenance items to attend to, then this process could take up to several weeks in order to be totally prepared for the test burn, even a short 3-day one.

Q. Would there be costs associated with those activities?

A. Again this could vary depending on what is involved. The costs would most likely be limited to labor and overhead associated with the time to communicate the information and to perform any associated tasks. However, if equipment or controls training is involved then there might be separate costs for this training, especially if provided by a vendor.

Q. If PEF decided to proceed with a 3-day short-term test burn, what is the next step?

A. At this point, careful planning and scheduling would be necessary. Since a limited amount of coal is procured and the environmental permit usually will specify a 30-day window with which to perform the testing, PEF would need to ensure that everything is coordinated carefully and that all necessary stakeholders are involved.

Q. What is involved in scheduling a short-term test burn?

A. Similar to the PRB test burn, the fuels department would need to purchase the test burn fuel blend and determine delivery dates, and there would be coordination required with other stakeholders including the Energy Control Center (ECC) to specify the test days and loads needed, the Environmental department to schedule the air testing team to conduct the required emissions testing (if required), plant operations to discuss the potential operational impacts expected from this fuel blend and what to look for, and the fuel handling group to discuss the plan for minimizing the safety risk that comes with handling the Spring Creek coal.

Q. Would employees have to be advised or trained on the handling and operational risks of handling Spring Creek coal?

A. Yes. Spring Creek coal has a very high moisture content which will tend to make the coal "sticky". Even blended with a relatively dry bituminous coal, this could lead to plugging issues in the conveyors, chutes or at turning points and would need to be monitored closely.

Q. Once a 3-day test burn is conducted, what is the next step?

A. PEF would analyze the results with the appropriate business units to determine the impact of burning the blended coal. If unit performance was acceptable and there were no significant problems, PEF might proceed with conducting a longer duration short-term test burn to better evaluate the impact of this coal on the units. The duration of the next test burn would be about 3 months.

Q. If PEF determined that the short-term test burn of Spring Creek merited a longer 3-month test, what would be the next step?

A. PEF would utilize the same process of reviewing the environmental, strategic, and operations issues before initiating a plan to move forward with a longer test of about three months duration.

Q. Can you estimate the amount of time it would entail to organize a longer-term, 3-month test burn?

A. It could take five to six months to coordinate the 3-month test burn. This could be longer depending on if capital equipment needs to be procured and installed prior to the test burn. As for coordination, there would need to be a review of the 3-day test burn information and a review of lessons learned from this short test. Following that, additional modifications to the testing protocol might be needed that focus more on the long-term impacts expected. Again, additional training of plant personnel would also be necessary to communicate the expected long-term impact and make sure they know what to look for during the test burn.

Since a longer term test burn has the potential to impact reliability of the unit(s), additional coordination would be needed with System Planning to minimize any impacts with other outages or work efforts elsewhere within the system. Depending on the situation at the time, it may not be feasible to schedule this test burn during high load periods such as during the summer or winter months.

Q. Would you consider capital upgrades before conducting a 3-month short-term test burn?

A. At this point, if the economic viability of Spring Creek coal is still valid, then the Company would likely invest in the capital additions recommended to minimize any reliability issues that might be encountered from the longer term test.

Q. If PEF determined that capital upgrades were necessary before conducting a longer test of Spring Creek coal, can you estimate how long it would take to purchase and install those upgrades?

A. Again, this can vary depending on the type of equipment needed, whether an outage was needed and if so, for how long. For some equipment, such as adding new retractable soot blowers, there might be a 3 month lead time to get the equipment in, but the installations could occur while a unit was online. This is assuming that available ports into the furnace were already there. However, for other equipment, such as water cannons, there may be a much longer lead time. The lead time for these items range from 9 to 12 months and they would require an outage for installation. Some items, such as installing an Intelligent Soot Blowing System, would also require an outage to change out the system controls. In addition, for this type of system, it would be necessary to for the vendor to spend a few additional weeks following the outage to "set-up" the software to ensure the soot blowing scenarios are programmed into the system based on the specific needs of each unit.

For any equipment that needs an outage to install, there would be additional coordination time with the plants and the System Planning Group to ensure the outage does not impact the overall system reliability in Florida. These outages are scheduled for either Fall or Spring, so they do not impact our high load seasons. It would most likely be necessary to delay installation until the appropriate timeframe, even if the equipment was delivered to the site earlier.

Q. Would there be costs associated with those capital upgrades?

A. Yes, please refer to Exhibit No. ___ (JS-8) for an estimate of these costs.

Q. Would it be necessary to consider any equipment operations issues before conducting a 3-month short-term test burn?

A. Yes, as mentioned earlier in my testimony, we would review the results collected from the 3-day test burn and then modify the test plan accordingly. We would also incorporate any additional information related to the longer-term impacts that are expected that may not be noticeable during the 3-day test. Some of these items might include looking for calcium sulfate build-up in the convection pass or "fouling". Fouling is different from slagging in that it can occur more gradually and its impacts may be less noticeable in the short term. However, the substances that cause fouling, such as calcium sulfate, can bond to the tubes and are more resistant to cleaning. If left unattended, it can completely clog the tubes in the convection pass and result in limiting the load as well as cause long outages for cleaning. So monitoring of this issue would be essential during a longer test burn.

In some instances, it might be necessary to gather baseline data of component integrity during the outage prior to the test burn for comparison following the test burn. This may result in additional downtime to conduct these inspections. An example of this would be to perform Ultrasonic Testing (UT) of the waterwalls to determine the tube thickness. Then following the 3-month test burn, perform a comparison of integrity to determine rate of erosion and wasteage attributed to newly installed water cannons.

Q. Can you estimate how much time it would take to perform necessary equipment operations training and testing before proceeding with a 3-month short-term test burn?

A. Again, this would depend on the extent of the differences from the 3-day test burn and the time needed to train employees on any new equipment or maintenance procedures. If significant capital additions are involved, it may be necessary to update any applicable simulator training as well.

Q. Would there be costs associated with those activities?

A. Yes, this would entail labor and overhead to coordinate and communicate the information plus any additional expenses associated with equipment training.

Q. Once a 3-month test burn is conducted, what is the next step?

A. PEF would analyze the test burn results with the appropriate business units to determine the impact of burning the blended coal. If unit performance was acceptable and there were no significant problems, PEF might proceed with conducting an extended test burn to better evaluate the impact of this coal on the units. An extended test burn may take 9 months to one year.

Q. If PEF determined that an extended test burn of Spring Creek was needed, what would the next step be?

A. PEF would once again review the environmental, strategic, and operations issues before initiating a plan to move forward with an extended test of about nine months to one year duration.

Q. Would you consider capital upgrades before conducting a long-term test burn?

A. Any capital upgrades at this point would be dependent upon what was installed prior to the 3-month test burn and any lessons learned from that exercise. Refer to Exhibit No. ___ (JS-8) for a list of capital additions.

Q. If PEF determined that capital upgrades were necessary before conducting a long-test of Spring Creek coal, can you estimate how long it would take to purchase and install those upgrades?

A. Just like the shorter burns, this would depend on the equipment lead times, if an environmental permit is needed prior to installation and timing with a Fall or Spring outage. Based on the extent of any new equipment installed, additional time and costs would need to be included for training.

Q. Based on all of your testimony thus far, then, could PEF have responsibly entered into a 3-year contract for Spring Creek coal in 2004 without determining how this coal would perform in the units?

A. No. From an operational, safety, and environmental perspective, the earliest PEF would have been able to burn this coal on an ongoing basis would have been sometime after August 2005, assuming everything went perfectly with all test burns and that no capital upgrades were needed. If capital upgrades were needed, the earliest PEF would have been able to burn Spring Creek coal would have been early 2007 to late 2007.

C. INDONESIAN COAL

Q. Please describe the coal qualities of PT Adaro Indonesian coal.

A. The PT Adaro Indonesian coal is also classified as a low rank Class C sub-bituminous coal. This coal, similar to other sub-bituminous coals, has very high moisture content, a low Btu value, a high oxygen and calcium content, a high propensity to gain and hold additional moisture due to its porous "sponge-like" structure and decomposes easily creating significant amount of coal fines or dust.

Unlike some other sub-bituminous coals, PT Adaro coal has an ultra-low sulfur content of 0.2 lb/MBtu. The PT Adaro coal also has a low percentage of ash, a lower self-heating temperature, a high percentage of iron, and a high Base to Acid ratio (B/A).

Q. Has PEF previously tested PT Adaro Indonesian coal?

A. No.

Q. Using the specification sheets provided with the 2006 PT Adaro Indonesian coal bid, how does this coal differ from the PRB coal previously tested by PEF?

A. As mentioned earlier, the PT Adaro coal has several coal quality composition factors which are different than the PRB coal previously tested. Some of these include differences in iron, calcium and sodium content as well as ash content. The Base to Acid ratio for the PT Adaro coal is 100% higher than for the PRB we previously tested.

In addition, the increased oxygen content of the PT Adaro coal would prompt additional investigation as oxygen content is inversely proportional to the self heating temperature for a coal. The PT Adaro's calculated self-heating potential is 47.4 degrees Fahrenheit, which is almost 50% less than for the PRB coal previously tested.

Another significant difference between the PT Adaro coal and the PRB coal tested previously is the ultra-low sulfur content which could negatively impact the ESP's performance.

Q. What impact might these coal differences have on CR Units 4 and 5?

A. From a safety perspective, the increase oxygen content in this coal could lead to an increased potential for fires or explosions. As the oxygen content in the coal goes up, the self-heating temperature comes down which increases the probability for spontaneous ignition that could lead to fires and explosions. In the spontaneous combustion of coal, the sources of heating are associated with the exothermic reaction from low-temperature oxidation in combination with absorption of moisture by dried or partially dried coal. The PT Adaro's calculated self-heating potential is 47.4 degrees Fahrenheit which is almost 50% less than the SHT of the PRB coal that the Commission considered in the 060658 Docket. Additional caution would need to be taken even with an 80/20 blend. If the dust from the 20% sub-bituminous portion localizes, which could occur as it degrades and breaks down through the handling process, this potential could increase and lead to unacceptable safety risks. In addition, higher bulk relative humidity and ambient temperatures favor spontaneous combustion which could present fuel handling issues throughout the year with Florida's climate, especially during the summer months.

Furthermore, the ultra-low sulfur content of this coal has the potential to significantly impact the opacity and particulate matter emissions from these units. While the low sulfur content may be advantageous for a reduction in SO_2 emissions, it can pose significant negative impacts to the performance of the electrostatic precipitator (ESP) which is used to control opacity and particulate matter emissions. Low-sulfur coals increase the resistivity of the fly ash, which is a measure of a material's opposition to the flow of electrical current. As resistivity goes up, the ESP's efficiency goes down. In addition, the high calcium percentage may also contribute to this inefficiency since the calcium in the ash will tend to bind with other sulfur in the ash to produce sulfates. These sulfates also have low conductivity and would increase the overall resistivity of the ash going into the ESP. A high resistivity will inhibit the flyash particles from becoming negatively charged by the electrodes and therefore will not be collected by the positively charged plates, which is the basic principal behind how an ESP works, leading to a higher amount of flyash or particulate matter escaping out the stack. A simplified diagram of an electrostatic precipitator along with an illustration showing the electrodes and collection plates is presented in Exhibit No. __ (JS-13).

Another phenomenon with high resistivity ash is the occurrence of "back corona". This takes place when the gas within a high resistivity dust layer becomes ionized, which causes heavy positive ion backflows, which then neutralizes the negative ion current. This reduces voltage levels and can increase the odds of a "sparkover."

The 100% increase in the Base to Acid ratio in this Indonesian coal over the PRB coal would also indicate a higher potential for slagging and fouling which would need to be investigated thoroughly. Increased slagging and fouling would cause impacts similar to the ones I listed previously for the Spring Creek coal such as increased maintenance costs, and increased potential for de-rates or offline time due to boiler cleaning or tube leaks.

Q. Please describe the coal qualities of PT Kideco Indonesian coal.

A. Similar to the other two coals, the PT Kideco Indonesian coal is classified as a low rank Class C sub-bituminous coal. This coal also has very high moisture content, a low Btu value, a high oxygen and calcium content, a high propensity to gain and hold additional moisture due to its porous "sponge-like" structure and decomposes easily creating significant amount of coal fines or dust.

Similarly to the PT Adaro coal, it has an ultra-low sulfur content of 0.2 lb/MBtu, a high percentage of iron and a high Base to Acid ratio (B/A). However the PT Kideco coal has an even higher percentage of ash.

Q. Has PEF previously tested PT Kideco Indonesian coal?

A. No.

Q. Using the specification sheets provided with the 2006 PT Kideco Indonesian coal bid, how does this coal differ from the PRB coal previously tested by PEF?

A. The PT Kideco coal has several coal quality composition factors which are different than the PRB coal previously tested. Some of these include differences in iron content that is almost 120% higher, along with differences in calcium, sodium and ash content. The Base to Acid ratio for the PT Kideco coal is almost 150% higher than for the PRB we previously tested.

In addition, the PT Kideco coal also has increased oxygen content and lower self-heating temperature similar to the PT Adaro coal that would prompt additional investigation on the potential for self ignition which could lead to fires or explosions. Again, a critically significant difference between the PT Kideco coal and the PRB coal tested previously is the ultra-low sulfur content, which as mentioned, could negatively impact the ESP's performance. And like the PT Adaro coal, the higher moisture content of this coal would indicate the potential for a decrease in the boiler efficiency and as the boiler efficiency goes down, the heat rate (Btu/kW) of the units would go up.

Q. What impact might these coal differences have on CR Units 4 and 5?

A. The impacts possible from the PT Kideco coal would be similar to those listed for the PT Adaro coal with respect to the increased potential for fires or explosions due to the lower self-heating temperature, reduced ESP efficiency due to the ultra-low sulfur content, the potential for a calcium binding effect which could also lead to an increase in opacity and particulate matter emissions, and the potential for an increase in slagging and fouling as indicated by the 142% increase in the Base to Acid ratio which could result in de-rates and more offline time for boiler cleaning and tube leaks.

Q. Do the characteristics of either of these Indonesian coals differ enough from the Wyoming PRB coal that PEF previously tested to merit a paper test burn of the coal?

A. Most definitely. Please refer to Exhibit No. __ (JS-12) which shows the timelines associated with the various testing an evaluation scenarios that would be employed when researching whether to move forward with burning Indonesian coal. I will provide additional detail on each of the aspects further in my testimony.

Q. If PEF were to consider burning either of these Indonesian coals, would PEF employ the same process that it has in the past to determine whether this coal could be successfully burned at CR Units 4 and 5?

A. Yes. Since both of these coals show the potential for operational, fuel handling, safety and environmental issues related to the differences between these coals to any that we have burned or tested in the past they would most likely fall under either the "Medium Fuel Case" or the "High Fuel Case" as reflected on my Exhibit No. __ (JS-11), depending on the results from the paper test associated with the significance levels of the expected issues and any benchmarking information we could gather from other users burning this fuel.

Q. Are there other considerations specific to these Indonesian Coals that would be different than or add additional steps to the process needed to evaluate Spring Creek Coal?

A. Yes. Since both of these coals exhibit ultra-low sulfur concentrations, there is an expectation that this could lead to ESP inefficiency and in turn cause higher opacity and particulate matter (PM) emissions. An air construction permit may need to be issued prior to the test burn that specifies the testing required to be performed during these test burns to quantify any emissions increases. Any emission increase that exceeds the Prevention of Significant Deterioration (PSD) trigger limit would be subject to a BACT Analysis (Best Available Control Technology) and potentially mandate additional pollution controls. The PSD trigger limit for Total PM is only 25 tons and this is based on the difference from a baseline value. The baseline value is determined from an average of the 2 highest years from the most recent 5 year timeframe. If it is determined that Total PM could increase more than 25 tons, then the BACT Analysis determination could specify that a baghouse must be installed in order to continue using this fuel.

In addition, exceeding any of the site's environmental permit limits, even during a test burn, would result in a Notice of Violation (NOV) and the test burn would need to be immediately stopped. The permit limits for both of these units were lowered when the site was issued the construction permit for the Clean Air Projects. For opacity, the limit was lowered from 20% to 10% and for particulate matter from 0.100lb/MBtu to 0.030 lb/MBtu.

Due to this expected increase in opacity and particulate emissions, equipment may need to be installed to mitigate this impact. Some utilities use a system which injects SO_3 upstream of the ESP to condition the fly ash to reduce this resistivity. However, this also leads to an increase in sulfuric acid mist emissions and this type of system would be extremely difficult, if not impossible, to permit due to these increases as there is no current technology available to reduce the sulfuric acid mist emissions at this point along the flow path.

If a decision was made to keep moving forward with a test burn, the only alternative to maintain opacity and particulate emission regulatory limits may be to expend significant capital dollars to add on a baghouse. This capital cost and the significant increase in maintenance costs would need to be included in the timeline and the overall economic analysis.

Q. Could PEF have responsibly burned the PT Adaro Indonesian coal in 2006 without determining how this coal would perform in the units?

A. No, it would not have been wise to commit to a contract for this coal until a thorough investigation was completed to determine how this coal would perform in the units or determine the other impacts to environmental compliance and safety.

Q. Could PEF have responsibly burned the PT Kideco Indonesian coal in 2006 without determining how this coal would perform in the units?

A. No, it similarly would have been unwise to commit to a contract for this coal until a thorough investigation was completed to determine how this coal would perform in the units or determine the other impacts to environmental compliance and safety.

Q. When could PEF first be in a position to responsibly burn this coal?

A. PEF would have completed the testing process for this coal somewhere between November 2008 and mid-October, 2009.

V. CONCLUSION

Q. Based on your work in this case, have you reached any conclusions regarding Mr. Putman's assertions that PEF could have burned Spring Creek and Indonesian coal in 2006 and 2007 in Crystal River Units 4 and 5?

A. Yes, as this Commission recognized in Docket 060658, PEF cannot simply choose to burn a new coal at Crystal River Units 4 and 5 without first engaging engineering in a stepwise and deliberate testing process to ensure continued operational performance, environmental compliance, and safety. This fact is not unknown to OPC or Mr. Putman. The Commission recognized the time involved with this process in Docket 060658 and estimated an approximate 2-year window for PEF to properly prepare itself to burn PRB coal (Order No. PSC-07-0816-FOF-EI, page 37).

Without testing, PEF cannot ensure the safety, reliability and output of these baseload generation units. It is not reasonable to assume that PEF could have burned the coal that Mr. Putman advances in his testimony without first taking prudent steps to test that coal, just like PEF did with the PRB coal the Commission considered in the previous case.

If PEF could have safely and effectively burned this coal on a long-term basis, a fact that only proper testing could prove, it would have been at least January to October, 2007 before PEF could have completed testing on Spring Creek coal, and at least November, 2008 to October, 2009 before PEF could have completed testing on Indonesian coal.

Q. Does this conclude your testimony?

A. Yes.

Kennecott Energy

May 11, 2004

Mrs. Robin Ott
Progress Fuels Corporation
One Progress Plaza, Suite 600
St. Petersburg, FL 33701

Dear Mrs. Ott:

Kennecott Energy Company, on behalf of Spring Creek Coal Company, is pleased to respond to your request to supply a portion of Progress Energy's requirements for the Crystal River Units 1 and 2 for the years 2005, 2006 and 2007.

COAL OFFERED

Origin — Spring Creek Coal - Big Horn County, Montana. Served by the BNSF Railroad.

Delivery Point — FOB Barge - Cahokia Terminal located in St. Louis, Missouri

Term/Quantity/Base Price

January 1, 2005 – December 31, 2007

Term	Quantity (To the nearest unit train.)	Price
2005	500,000 Tons	\$22.90/ Ton
2006	500,000 Tons	\$22.90/ Ton
2007	500,000 Tons	\$22.90/ Ton

Prices are pnt FOB Barge Cahokia Terminal, St. Louis, Missouri based on coal having a standard heating value of 9,350 Btu/lb and a standard sulfur value of 0.80bs. SO_2/MMBtu. The Base Prices include Kennecott's best estimate of all Third Party costs as defined in Adjustment Provisions hereinbelow as of May 11, 2004. The standard heating and sulfur values are for price adjustment purposes only. The price shall be subject to adjustment for variations in the monthly weighted average calorific value from the standard heating value on an FOB mine basis and for variation in SO_2 content from the standard sulfur value in accordance with a mutually agreed upon SO_2 adjustment provision.

Sixty-Five percent (65%) of the above listed prices will be adjusted at 100% of the RCAF-U on a quarterly basis and a fuel surcharge adjustment monthly.

Typical Quality (Annual Average)

Typical Values	2005 - 2007
Btu	9,350
Moisture	22.36%
Ash	4.0%
Sulfur (Lbs. SO_2/mmBtu)	0.80
Sodium (Na2O)	8.00%

PEF-FUEL-000443

Adjustment Provisions	Third Party Cost & New Laws Adjustments Third party costs include any and all taxes, fees, royalties, and governmental impositions paid to third parties on or attributable to the production of coal. Any change in these items from May 11, 2004, either up or down, will be passed on to Buyer. A change could be a change in rate changes resulting from a new law or regulation or change in interpretation (or estimate by Seller of impact) of an existing law or regulation on a federal, state or local level. The adjustments will be passed through as of the date of the actual change resulting in such adjustments.
Sampling & Analysis	In accordance with ASTM standards for Spring Creek Coal Company.
Data Transmission	As mutually agreed upon.
Delivery Schedule	As mutually agreed upon.
Weights	In accordance with Spring Creek Coal Company "certified" mine weights.
Mine Information	See attached
Terms & Conditions	This offer is considered proprietary and confidential; it should not be divulged to third parties without the express written approval of Kennecott Energy Company. Specific terms and conditions of a prospective agreement are subject to mutual agreement. Attached is a Master Coal Purchase and Sale Agreement that will represent a starting point for discussions. Coal is offered subject to prior sale and availability and in any event, this offer will expire after May 17, 2004, unless negotiations leading to a definitive agreement have commenced by that date; in which case the offer may be extended. Acceptance of this offer must be received, in writing, no later than 5:00 PM MDT on or before May 17, 2004. This offer and Kennecott Energy Company's obligation to enter into a coal supply agreement is subject to Kennecott Energy Company's internal credit review and approval.

We appreciate this opportunity to supply a portion of your coal requirements. If you have any questions or comments, please contact me at 307.685.6114.

Sincerely,

B.A. Miller

Bruce A. Miller
Manager, Origination and Structured Products

BAM:ksn

N:\GCC_MKTG\PROPOSAL\2004 Domestic\Spring Creek\Progress Energy_SCC Only_05-11-04.doc

SPRING CREEK COAL MINE
2005 QUALITY SPECIFICATIONS

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE -2 STD DEV	+2 STD DEV	TYPICAL DRY VALUE	TYPICAL MOISTURE-ASH FREE VALUE
PROXIMATE						
% Moisture	25.40	0.56	24.28	26.52		
% Ash	4.12	0.33	3.46	4.78	5.52	
% Volatile	31.26	0.81	29.64	32.88	41.90	44.35
% Fixed Carbon	39.23	0.80	37.63	40.83	52.59	55.66
BTU/lb	9350	103	9144	9556	12534	13266
MAFBTU	13266	80.08	13106	13426		
Dry BTU	12534	93.71	12346	12721		
% Sulfur	0.34	0.07	0.20	0.48	0.46	0.48
ULTIMATE						
% Moisture	25.40	0.56	24.28	26.52		
% Carbon	54.14	3.28	47.58	60.70	72.57	76.82
% Hydrogen	3.80	0.23	3.34	4.26	5.09	5.39
% Nitrogen	0.71	0.09	0.53	0.89	0.95	1.01
% Chlorine	0.00	0.01	0.00	0.01	0.00	0.00
% Sulfur	0.34	0.07	0.20	0.48	0.46	0.48
% Ash	4.12	0.33	3.46	4.78		
% Oxygen	11.50	0.70	10.10	12.90	15.42	16.32
SULFUR FORMS						
Pyritic Sulfur (%)	0.05	0.03	0.00	0.11	0.07	0.07
Sulfate Sulfur (%)	0.01	0.015	0.00	0.04	0.01	0.01
Organic Sulfur (%)	0.28	0.06	0.16	0.40	0.38	0.40
Total Sulfur (%)	0.34	0.07	0.20	0.48	0.46	0.48
MINERAL ANALYSIS OF ASH						
% Silicon Dioxide (Silica, SiO_2)	32.52	2.78	26.96	38.08	43.59	46.14
% Aluminum Oxide (Alumina, Al_2O_3)	17.69	1.09	15.51	19.87	23.71	25.10
% Titanium Dioxide (Titania, TiO_2)	1.13	0.10	0.93	1.33	1.51	1.60
% Iron Oxide (Ferric Oxide, Fe_2O_3)	4.76	0.47	3.82	5.70	6.38	6.75
% Calcium Oxide (Lime, CaO)	15.36	1.41	12.54	18.18	20.59	21.79
% Magnesium Oxide (Magnesia, MgO)	3.69	0.85	1.99	5.39	4.95	5.24
% Potassium Oxide (K_2O)	0.63	0.14	0.35	0.91	0.84	0.89
% Sodium Oxide (Na_2O)	8.24	1.00	6.24	10.24	11.05	11.69
% Sulfur Trioxide (SO_3)	14.07	2.50	9.07	19.07	18.86	19.96
% Phosphorous Pentoxide (P_2O_5)	0.35	0.06	0.23	0.47	0.47	0.50
% Strontium Oxide (SrO)	0.37	0.22	0.00	0.81	0.50	0.52
% Barium Oxide (BaO)	1.19	0.31	0.57	1.81	1.60	1.69
% Undetermined	0.00	1.00	0.00	2.00	0.00	0.00
Base/Acid Ratio	0.64	0.08	0.48	0.80		
Base Value	32.66	2.20	28.28	37.08		
Acid Value	51.34	3.00	45.34	57.34		
ASH FUSION TEMPERATURES						
Reducing (°F)						
Initial	2106	37	2031	2181		
Softening (H=W)	2129	36	2056	2202		
Hemispherical (H=1/2W)	2141	39	2062	2220		
Fluid	2164	51	2062	2266		
Fluid-Initial Temp. Difference	58	40	0	138		
Oxidizing (°F)						
Initial	2351	98	2156	2546		
Softening (H=W)	2366	81	2204	2528		
Hemispherical (H=1/2W)	2391	73	2245	2537		
Fluid	2423	77	2268	2578		
Fluid-Initial Temp. Difference	72	60	0	192		

SPRING CREEK COAL MINE
QUALITY SPECIFICATIONS (Continued)

QUALITY PARAMETER

ADDITIONAL ANALYSES AND CALCULATED VALUES

	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE -2 STD DEV	+2 STD DEV
T250 Temperature (°F)	2153	91.88	1969	2337
HGI (at as-received moisture)	60.6	5.6	49	72
HGI % Moisture	24.13	3.88	16	32
Critical Viscosity Temperature (°F)	0	0	0	0
Critical Viscosity (Poises)	0	0	0	0
% Equilibrium Moisture	23.93	0.56	22.81	25.05
Specific Gravity	1.10	0.015	1.07	1.13
%Alkalies NA2O Dry (Total Alkali Content on Coal;	0.478	0.070	0.34	0.62
%Water Soluble Alk - Na2O	0.000	0.000	0.00	0.00
%Water Soluble Alk - K2O	0.000	0.000	0.00	0.00
%Na2O - Dry Coal	0.46	0.03	0.40	0.52
%Na2O As-received Coal	0.34	0.02	0.30	0.38
Silica Value (Silica Ratio)	57.73			
Slag Factor	0.28	0.14	0.00	0.56
Slag factor per Fusion Temperature	2163	85	1993	2333
Dolomite Ratio	58.29	3.25	51.79	64.79
Ash Precipitation Index	3.97	10.1	0.00	24.17
Silica to Alumina Ratio	1.84	0.14	1.56	2.12
Calcium to Silica Ratio	0.47	0.34	0.00	1.15
Iron to Calcium Ratio	0.31	0.07	0.17	0.45
Fouling Factor (Fouling Index)	5.25	1.41	2.43	8.07
SO2/MMBTU	0.80	0.075	0.65	0.95
lbs S/MMBTU	0.36	0.075	0.21	0.51
lbs Sodium/MMBTU	0.363	0.023	0.32	0.41
lbs Ash/MMBTU	4.41	0.5	3.41	5.41

TYPICAL COAL SIZE 2 inch

Size Fraction	Wt. Percent	Cumulative Wt. Percent	Wt. Percent Passing Top
+3" RD.	0%	0%	100%
3" RD. x 2" RD.	4%	4%	100%
2" RD. x 1" RD.	20%	24%	96%
1" RD. x 1/2" RD.	28%	52%	76%
1/2" RD. x 4 M	20%	71%	48%
4 M x 60 M	13%	84%	29%
60 M x 0	16%	100%	16%

TRACE ELEMENT SUMMARY
Parts Per Million
Whole Coal, Dry Basis

	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE -2 STD DEV	+2 STD DEV
ANTIMONY (Sb)	0.00	0.00	0.00	0.00
ARSENIC (As)	1.50	1.00	0.00	3.50
BARIUM (Ba)	0.00	0.00	0.00	0.00
BERYLLIUM (Be)	0.21	0.08	0.06	0.36
BORON (B)	0.00	0.00	0.00	0.00
BROMIDE (Br)	0.00	0.00	0.00	0.00
CADMIUM (Cd)	0.18	0.02	0.14	0.22
CHLORINE (Cl)	0.00	0.00	0.00	0.00
CHROMIUM (Cr)	2.40	0.75	0.90	3.90
COBALT (Co)	0.00	0.00	0.00	0.00
COPPER (Cu)	0.00	0.00	0.00	0.00
FLUORINE (F)	41.90	11.00	19.90	63.90
LITHIUM (Li)	0.00	0.00	0.00	0.00
MANGANESE Mn)	16.20	7.90	0.40	32.00
MERCURY (Hg)	0.07	0.03	0.01	0.13
MOLYBDNEUM (Mo)	0.00	0.00	0.00	0.00
NICKEL (Ni)	1.53	1.00	0.00	3.53
LEAD (Pb)	2.60	1.00	0.60	4.60
SELENUIM (Se)	1.20	0.90	0.00	3.00
SILVER (Ag)	0.00	0.00	0.00	0.00
STRONTIUM (Sr)	0.00	0.00	0.00	0.00
THALLIUM (Tl)	0.00	0.00	0.00	0.00
THORIUM (Th)	0.00	0.00	0.00	0.00
TIN (Sn)	0.00	0.00	0.00	0.00
URANIUM (U)	0.00	0.00	0.00	0.00
VANADIUM (V)	0.00	0.00	0.00	0.00
ZIRCONIUM (Zr)	0.00	0.00	0.00	0.00
ZINC (Zn)	0.00	0.00	0.00	0.00

* All negative numbers were converted to 0.0(

Revised 3/29/2000

Spring Creek Coal Company

Spring Creek Coal Company began operations in 1980 with a design capacity of 11.0 million tons per year. Spring Creek has a federal lease consisting of 2,505 acres and a state lease consisting of 642 acres. The current recoverable reserves at the end of 1999 were approximately 221 million tons. Current mining involves a single coal seam 80 feet thick. Mining is carried out primarily by dragline operations.

Mine Name:	Spring Creek Coal Company
Location:	Southeast Montana, Big Horn County, 35 miles from Sheridan, Wyoming U.S.A.
Served by:	Burlington Northern Railroad
Rail Loading Point:	NERCO Junction, Montana
Mine Type:	Surface
Seams:	Anderson-Dietz 1 & 2
Recoverable Reserves:	221 Million Tons
Annual Production Capacity:	11.0 Million Tons
Processed Coal Storage Capacity:	36,000 Tons (Storage Barn)
Weighing System:	Ramsey Engineering conveyor belt scales. Coal is weighed, as it is flood loaded into railcars. Scales certified semi-annually in accordance with the Western Weighing and Inspection Bureau.
Sampling & Analysis:	Ramsey Engineering three-stage mechanical sampling system. On-site, by Commercial Testing & Engineering Laboratories, in accordance with ASTM standards.
Blending Capability:	Coal is simultaneously mined from two or more mining areas and blended as required with additional blending capability from the storage barn.
Loading Rate:	4,000 tons per hour. 113 car train in approximately 4.0 hours.
Load Track Configuration & Capacity:	One mile full loop with two unit-train capacity.
Washing Capability:	None
Dust Suppression:	Chem-Loc 101 is applied to all production at an aggregate rate of 1.2 gallons of diluted chemical per ton of coal. Application occurs throughout the coal handling process and prior to being transferred into the storage barn. Freezeproofing and side-release chemical agents can be applied upon request.
Size:	2" x 0"
Density:	In place: 80 lb./ft^3 Crushed: 55 lb./ft^3
Angle of Repose:	Approximately 3 : 1

PEF-FUEL-000447

Kennecott Energy

CONFIDENTIAL

May 11, 2004

Mrs. Robin Ott
Progress Fuels Corporation
One Progress Plaza, Suite 600
St. Petersburg, FL 33701

[illegible]

Dear Mrs. Ott:

Kennecott Energy Company is pleased to respond to your request to supply a portion of Progress Energy's requirements for the Crystal River Units 1 and 2 for the years 2005, 2006 and 2007. The following coal offered represents a blended coal from Kennecott Energy's Spring Creek mine located in Decker, Montana and Knight Hawk Coal LLC Creek Paum Mine located in Ava, Illinois.

COAL OFFERED

Origin	Seventy-five percent Spring Creek Coal –Big Horn County, Montana Twenty-five percent Knight Hawk Coal – Ava, Illinois
Delivery Point	FOB Barge - Cahokia Terminal located in St. Louis, Missouri
Term/Quantity/Base Price	

January 1, 2005 – December 31, 2007

Term	Quantity (To the nearest unit train.)	Price
2005	200,000 Tons	$27.74/ Ton
2006	400,000 Tons	*
2007	400,000 Tons	*

Prices are pnt FOB Barge Cahokia Terminal, St. Louis, Missouri based on coal having a standard heating value of 9,963 Btu/lb and a standard sulfur value of 1.18 lbs. SO_2/MMBtu. The Base Prices include Kennecott's best estimate of all Third Party costs as defined in Adjustment Provisions hereinbelow as of May 11, 2004. The standard heating and sulfur values are for price adjustment purposes only. The price shall be subject to adjustment for variations in the monthly weighted average calorific value from the standard heating value on an FOB mine basis and for variation in SO_2 content from the standard sulfur value in accordance with a mutually agreed upon SO_2 adjustment provision.

* The transportation component of $16.00 will escalate based on 100% of the RCAF-U on a quarterly basis and a fuel surcharge adjustment monthly.

Typical Quality (Annual Average)

Typical Values	2005 - 2007
Btu	9,963
Moisture	13.22%
Ash	5.0%
Sulfur (Lbs. SO_2/mmBtu)	1.18
Sodium (Na2O)	5.00%

PEF-FUEL-000405

Adjustment Provisions	Third Party Cost & New Laws Adjustments Third party costs include any and all taxes, fees, royalties, and governmental impositions paid to third parties on or attributable to the production of coal. Any change in these items from May 11, 2004, either up or down, will be passed on to Buyer. A change could be a change in rate changes resulting from a new law or regulation or change in interpretation (or estimate by Seller of impact) of an existing law or regulation on a federal, state or local level. The adjustments will be passed through as of the date of the actual change resulting in such adjustments.
Sampling & Analysis	In accordance with ASTM standards for Spring Creek Coal Company.
Data Transmission	As mutually agreed upon.
Delivery Schedule	As mutually agreed upon.
Weights	In accordance with Kennecott Energy and Knight Hawk Coal "certified" mine weights.
Terms & Conditions	This offer is considered proprietary and confidential; it should not be divulged to third parties without the express written approval of Kennecott Energy Company. Specific **terms and conditions of a prospective agreement are subject to mutual agreement. Attached is a Master Coal Purchase and Sale Agreement that will represent a starting point for discussions. Coal is offered subject to prior sale and availability and in any event, this offer will expire after May 17, 2004,** unless negotiations leading to a definitive agreement have commenced by that date; in which case the offer may be extended. **Acceptance of this offer must be received, in writing, no later than 5:00 PM MDT on or before May 17, 2004.** This offer and Kennecott Energy Company's obligation to enter into a coal supply agreement is subject to Kennecott Energy Company's internal credit review and approval.

We appreciate this opportunity to supply a portion of your coal requirements. If you have any questions or comments, please contact me at 307.685.6114.

Sincerely,

Bruce A. Miller
Manager, Origination and Structured Products

BAM:ksn

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Knight Hawk
Creek Paum Mine
2003QUALITY SPECIFICATIONS

Trainload reject parameters: 11000 BTU; 8.0 lbs SO2 per mm

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 9: -2 STD DEV
PROXIMATE			
% Moisture	13.22		
% Ash	5.11		
% Volatile	3.00		
% Fixed Carbon	32.61		
BTU/lb	11900		
MAFBTU	14571		
Dry BTU	13713		
% Sulfur	1.28		
ULTIMATE			
% Moisture	13.22		
% Carbon	67.46		
% Hydrogen	4.71		
% Nitrogen	1.54		
% Chlorine	<0.01		
% Sulfur	1.28		
% Ash	5.11		
% Oxygen	6.67		
SULFUR FORMS			
Pyritic Sulfur (%)	0.64		
Sulfate Sulfur (%)	0.03		
Organic Sulfur (%)	0.61		
Total Sulfur (%)	1.28		
MINERAL ANALYSIS OF ASH			
% Silicon Dioxide (Silica, SiO2)	46.79		
% Aluminum Oxide (Alumina, Al2O3)	21.42		
% Titanium Dioxide (Titania, TiO2)	1.18		
% Iron Oxide (Ferric Oxide, Fe2O3)	20.96		
% Calcium Oxide (Lime, CaO)	2.59		
% Magnesium Oxide (Magnesia, MgO)	0.94		

% Potassium Oxide (K2O)	2.86
% Sodium Oxide (Na2O)	0.61
% Sulfur Trioxide (SO3)	1.16
% Phosphorous Pentoxide (P2O5)	0.69
% Strontium Oxide (SrO)	0.10
% Barium Oxide (BaO)	0.05
% Undetermined	0.63
Base/Acid Ratio	0.40
Base Value	
Acid Value	

ASH FUSION TEMPERATURES

Reducing (^{o}F)	
Initial	1965
Softening (H=W)	2010
Hemispherical (H=1/2W)	2060
Fluid	2180
Fluid-Initial Temp. Difference	215
Oxidizing (^{o}F)	
Initial	2430
Softening (H=W)	2480
Hemispherical (H=1/2W)	2500
Fluid	2550
Fluid-Initial Temp. Difference	120

Knight Hawk
QUALITY SPECIFICATIONS (Continued)

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 9! -2 STD DEV
ADDITIONAL ANALYSES AND CALCULATED VALUES			
T250 Temperature (^{o}F)	2408		
HGI (at as-received moisture)	52		
HGI % Moisture			
Critical Viscosity Temperature (^{o}F)			
Critical Viscosity (Poises)			
% Equilibrium Moisture			
Specific Gravity			
%Alkalies NA2O Dry (Total Alkali Content on Coal)			
%Water Soluble Alk - Na2O			
%Water Soluble Alk - K2O			

%Na2O - Dry Coal	
%Na2O As-received Coal	
Silica Value (Silica Ratio)	65.64
Slag Factor	0.59
Slag factor per Fusion Temperature	
Dolomite Ratio	
Ash Precipitation Index	
Silica to Alumina Ratio	
Calcium to Silica Ratio	
Iron to Calcium Ratio	
Fouling Factor (Fouling Index)	0.24
SO2/MMBTU	2.15
lbs S/MMBTU	1.08
lbs Sodium/MMBTU	0.026
lbs Ash/MMBTU	4.29

TYPICAL COAL SIZE 2 inch

Size Fraction	Wt. Percent	Cumulative Wt. Percent
+3" RD.		
3" RD. x 2" RD.		
2" RD. x 1" RD.		
1" RD. x 1/2" RD.		
1/2" RD. x 4 M		
4 M x 60 M		
60 M x 0		

TRACE ELEMENT SUMMARY

Parts Per Million Whole Coal, Dry Basis	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 9! -2 STD DEV
ANTIMONY (Sb)			
ARSENIC (As)			
BARIUM (Ba)			
BERYLLIUM (Be)			
BORON (B)			
BROMIDE (Br)			
CADMIUM (Cd)			
CHLORINE (Cl)			
CHROMIUM (Cr)			
COBALT (Co)			
COPPER (Cu)			
FLUORINE (F)			
LITHIUM (Li)			
MANGANESE Mn)			
MERCURY (Hg)			
MOLYBDNEUM (Mo)			
NICKEL (Ni)			
LEAD (Pb)			
SELENUIM (Se)			
SILVER (Ag)			
STRONTIUM (Sr)			

THALLIUM (Tl)
THORIUM (Th)
TIN (Sn)
URANIUM (U)
VANADIUM (V)
ZIRCONIUM (Zr)
ZINC (Zn)

*** All negative numbers were converted to 0.00**

PROGRESS Energy Florida

PRODUCER NAME: PT Adaro Indonesia

STREET ADDRESS: 1401 Manatee Avenue West, Suite 910, Bradenton, Florida 34205

CONTACT: Pamela E. Solomon | CONTACT: Pamela E. Solomon

MINE(S): Tutupan BOM DISTRICT: | MINE(S): Tutupan | MINE(S): Tutupan

TYPE OF LOADING FACILITY:
UNIT TRAIN: ___________ SINGLE CAR: ____ TRAINLOAD: ___________ | TYPE OF LOADING FACILITY: UNIT TRAIN: ___________

MAXIMUM LOADING CAPACITY:
___________ TONS ___________ HOURS ___________ TRACK CAPACITY

WATER DELIVERY CAPABILITY: X YES ____ NO IMPORT COAL:LOAD PORT Taboneo Anchorage load rate 10,000 MTWWDSHINC; International Bulk Terminal load rate 20,000 MTWWDSHINC

TOTAL PRODUCTION CAPACITY PER MONTH: 3,000,000 TONS

PRODUCTION PER MONTH—MEETING OUR COAL SPECIFICATIONS: 2,000,000 TONS

TYPE OF MINE: 100% SURFACE

SEAMS: N/A

COAL PREPARATION: 100% RAW 0% WASHED 0% COMBINATION

TYPE OF COAL WASHER, IF WASHED: N/A

PE OF COAL SAMPLING:

TYPE OF LABOR CONTRACT(S):

TYPE OF COAL WEIGHING: | TYPE OF COAL WEIGHING:

PERIOD	TONNAGE	BASE PRICE PER TON FOB MINE
2007, 2008, 2009	150,000 mt	$33.50 fob

IF THIS COAL IS OFFERED BY A COMPANY OR INDIVIDUAL WHICH IS NOT THE PRODUCER PLEASE INDICATE SO BY MAKING AN "X" IN THIS SPOT.

PRODUCER'S COMMENTS:

CREDIT REFERENCES (Minimum two):

INDUSTRY REFERENCES (Minimum four):

SIGNATURE: Pamela E. Solomon | TITLE: Sales Manager | DATE: 2/10/2006

MAIL THIS FORM AND ANY ADDITIONAL INFORMATION TO:
Ms. Annette Britton
annette.britton@pgnmail.com
c/o Progress Energy Carolinas, Inc. Regulated Fuels Department
410 S. Wilmington Street
Mail Code PEB10
Raleigh, NC 27601

DESCRIPTION	OFFERED COAL SPECIFICATIONS		REQUIRED COAL SPECIFICATIONS	
	"AS RECEIVED" AVERAGE OR TYPICAL	"AS RECEIVED" GUARANTEED	BITUMINOUS "AS RECEIVED" GUARANTEED	SUB-BITUMINOUS "AS RECEIVED" GUARANTEED
MOISTURE (TOTAL) %	26	N/A	8.0% MAX.	30.0% MAX.
SURFACE MOISTURE %	26	N/A	5.0% MAX.	5.0% MAX.
ASH %	1.2	N/A	10.0% MAX.[2]	7.8% MAX.[2]
SULFUR DIOXIDE (LB/MBTU)	0.1	N/A	1.2 LB/MAX.[1]	1.2 LB/MAX.[1]
BTU/LB	9,300	N/A	12,300 MIN.	8,200/LB MIN.
ASH SOFTENING DEGREES FAHRENHEIT H=W (R)	1,240	N/A	2,500 MIN.	2,200 MIN.
VOLATILE %	37.2	N/A	31.0% MIN.[1]	31.0% MIN.[1]
GRINDABILITY, HARDGROVE	48	N/A	42 MIN.[3]	65 MIN.[3]
SIZE	2" x 0"	N/A	2" X 0"	2" X 0"
FINES (-1/4" X 0")	N/A	N/A	45% MAX.[5]	30% MAX.[5]
PYRITIC SULFUR	0.01	N/A	0.2% MAX.[1]	0.2% MAX.[1]
FIXED CARBON %	35	N/A	——	——
HYDROGEN %	3.5	N/A	——	——
NITROGEN %	0.6	N/A	——	——
CHLORINE %	0.01	N/A	——	——
OXYGEN %	14.5	N/A	——	——

[1]Must be met on an individual shipment basis.
[2]Adjustable in direct proportion to Btu.
[3]Adjustable in inverse proportion to Btu.
[4]Economic analyses will be based on these values.
[5]Preferred value, coals not meeting this specification will be considered.

MINERAL ANALYSIS %WEIGHT			TRACE ELEMENTS PPM IN COAL		
DESCRIPTION	AVERAGE	STD. DEV.	DESCRIPTION	AVERAGE	STD DEV.
P_2O_5	0.3	N/A	Antimony	0.05	N/A
SiO_2	35	N/A	Arsenic	0.8	N/A
Fe_2O_3	20	N/A	Beryllium	0.5	N/A
Al_2O_3	20	N/A	Cadmium	0.01	N/A
TiO_2	1.0	N/A	Chromium	1	N/A
CaO	11	N/A	Cobalt	1.1	N/A
MgO	3.0	N/A	Fluorine	No data	N/A
SO_3	9.0	N/A	Lead	1.2	N/A
K_2O	0.7	N/A	Lithium	0.6	N/A
Na_2O	0.3	N/A	Manganese	15	N/A
Undetermined	N/A	N/A	Mercury	0.1	N/A
Base/Acid Ratio	0.6	N/A	Nickel	2	N/A
Maximum Base/Acid Ratio	N/A	N/A	Selenium	0.12	N/A

*NOTE: ADD SHEETS IF MORE THAN ONE SEAM

DESCRIPTION	OFFERED COAL SPECIFICATIONS		REQUIRED COAL SPECIFICATIONS	
	"AS RECEIVED" AVERAGE OR TYPICAL	"AS RECEIVED" GUARANTEED	BITUMINOUS "AS RECEIVED" GUARANTEED	SUB-BITUMINOUS "AS RECEIVED" GUARANTEED
MOISTURE (TOTAL) %	26	N/A	8.0% MAX.	30.0% MAX.
SURFACE MOISTURE %	26	N/A	5.0% MAX.	5.0% MAX.
ASH %	1.2	N/A	10.0% MAX.[2]	7.8% MAX.[2]
SULFUR DIOXIDE (LB/MBTU)	0.1	N/A	1.2 LB/MAX.[1]	1.2 LB/MAX.[1]
BTU/LB	9,300	N/A	12,300 MIN.	8,200/LB MIN.
ASH SOFTENING DEGREES FAHRENHEIT H=W (R)	1,240	N/A	2,500 MIN.	2,200 MIN.
VOLATILE %	37.2	N/A	31.0% MIN.[1]	31.0% MIN.[1]
GRINDABILITY, HARDGROVE	48	N/A	42 MIN.[3]	65 MIN.[3]
SIZE	2" x 0"	N/A	2" X 0"	2" X 0"
FINES (-1/4" X 0")	N/A	N/A	45% MAX.[5]	30% MAX.[5]
PYRITIC SULFUR	0.01	N/A	0.2% MAX.[1]	0.2% MAX.[1]
FIXED CARBON %	35	N/A	——	——
YDROGEN %	0.6	N/A	——	——
TROGEN %	0.6	N/A	——	——
CHLORINE %	0.01	N/A	——	——
OXYGEN %	14.5	N/A	——	——

[1]Must be met on an individual shipment basis.
[2]Adjustable in direct proportion to Btu.
[3]Adjustable in inverse proportion to Btu.
[4]Economic analyses will be based on these values.
[5]Preferred value, coals not meeting this specification will be considered.

MINERAL ANALYSIS %WEIGHT			TRACE ELEMENTS PPM IN COAL		
DESCRIPTION	AVERAGE	STD. DEV.	DESCRIPTION	AVERAGE	STD DEV.
P_2O_5	0.3	N/A	Antimony	0.05	N/A
SiO_2	35	N/A	Arsenic	0.8	N/A
Fe_2O_3	20	N/A	Beryllium	0.5	N/A
Al_2O_3	20	N/A	Cadmium	0.01	N/A
TiO_2	1.0	N/A	Chromium	1	N/A
CaO	11	N/A	Cobalt	1.1	N/A
MgO	3.0	N/A	Fluorine	No data	N/A
SO_3	9.0	N/A	Lead	1.2	N/A
K_2O	0.7	N/A	Lithium	0.6	N/A
Na_2O	0.3	N/A	Manganese	15	N/A
determined	N/A	N/A	Mercury	0.1	N/A
Base/Acid Ratio	0.6	N/A	Nickel	2	N/A
Maximum Base/Acid Ratio	N/A	N/A	Selenium	0.12	N/A

*NOTE: ADD SHEETS IF MORE THAN ONE SEAM

SUCOFINDO
WORLDWIDE SERVICES
CORRESPONDENTS OF :
SGS Société Générale de Surveillance S.A., GENEVA.
Issuing office : Coal Services-SBU Lab.
Graha Sucofindo 6th Floor
Ph. (6221) 7986557. Fax (6221) 7986878

PT. SUPERINTENI
HEAD OFFICE : GRAHA SUCO
JAKARTA 12780 PO BOX 2377
FAX : (021) 7983888 TELEX : 6

No. : 361125.

CERTIFICATE OF ANALYSIS

VESSEL	:	**MV. GENCO LEADER**
CARGO	:	**76,252 ST (= 69,175 MT)**
COMMODITY	:	**ENVIROCOAL IN BULK**
BUYER	:	
SHIPPER	:	**PT. ADARO INDONESIA** **Suite 704, World Trade Center** **Jl. Jend. Sudirman Kav. 31,** **Jakarta 12920**
LOADING PORT	:	**Taboneo Anchorage, Banjarmasin,** **South Kalimantan, Indonesia**
LOADING DATES	:	**October 28 to November 01, 2005**

Samples were drawn during loading using the mechanical sampling system at the terminal. Samples were prepared and analyzed in accordance with ASTM Standard methods with average results as follow :

Test		**Result**	**ASTM Designation No.**
Total Moisture, % wt, as received basis, ...	:	27.1	ASTM D3302
Proximate Analysis :			
- Inherent Moisture, % wt, air dried basis, ...	:	14.5	
- Ash, % wt, as received basis, ...	:	1.2	ASTM D3174
- Volatile Matter, % wt, as received basis, ...	:	36.9	ASTM D3175
- Fixed Carbon, % wt, as received basis, ...	:	34.8	
Total Sulphur, % wt, as received basis, ...	:	0.09	ASTM D3177
Gross Calorific Value, btu / lb, as received basis, ..	:	9175	ASTM D5865
Hardgrove Grindability Index	:	51	ASTM D409
Lb. SO_2 / MMBtu, (Sulphur Dioxide) dry basis, ...	:	0.18	
Sizing :			
Less than 0.25 inch ,% wt, ...	:	35.0	

Cont'd. to page .2/..

PEF-CC-000305

Certificate of Analysis

ULTIMATE ANALYSIS (Dry Basis) :

- Carbon	,% wt,	:	72.7	ASTM D3178
- Hydrogen	,% wt,	:	5.33	ASTM D3178
- Nitrogen	,% wt,	:	0.82	ASTM D3179
- Oxygen	,% wt,	:	19.51	By Difference
- Sulphur	,% wt,	:	0.13	ASTM D3177

ASH COMPOSITION (Dry Basis) :

- SiO_2	,% wt,	:	31.40	ASTM D3682
- Al_2O_3	,% wt,	:	16.49	ASTM D3682
- Fe_2O_3	,% wt,	:	21.74	ASTM D3682
- CaO	,% wt,	:	11.41	ASTM D3682
- MgO	,% wt,	:	7.06	ASTM D3682
- Na_2O	,% wt,	:	0.16	ASTM D3682
- K_2O	,% wt,	:	0.66	ASTM D3682
- Mn_3O_4	,% wt,	:	0.27	ASTM D3682
- TiO_2	,% wt,	:	0.71	ASTM D3682
- P_2O_5	,% wt,	:	0.33	ASTM D3682
- SO_3	,% wt,	:	9.32	ASTM D3682

ASH FUSION TEMPERATURES :

			Reducing Atmosphere	Oxidizing Atmosphere	
- Initial Deformation (IT)	, °F,	:	2192	2282	ASTM D1857
- Softening (ST)	, °F,	:	2219	2327	ASTM D1857
- Hemispherical	, °F,	:	2228	2336	ASTM D1857
- Fluidity (FT)	, °F,	:	2264	2372	ASTM D1857

OTHER PROPERTIES (Dry Basis) :

- Mercury	, ppm, in coal	:	0.03	ASTM D6414

Cont'd to page ..3/..

MP

PEF-CC-000306

SUCOFINDO
WORLDWIDE SERVICES
CORRESPONDENTS OF :
SGS Société Générale de Surveillance S.A., GENEVA.
Issuing office : Coal Services-SBU Lab.
Graha Sucofindo 6th Floor
Ph. (6221) 7986557, Fax (6221) 7986878

HEAD OFFICE : GRAHA SUC...
JAKARTA 12780 PO BOX 23...
FAX : (021) 7983888 TELEX : ...

No. : 36146...

CERTIFICATE OF ANALYSIS

VESSEL	:	MV. RUBY CREST
CARGO	:	78,272 ST (= 71,008 MT)
COMMODITY	:	ENVIROCOAL IN BULK
BUYER	:	
SHIPPER	:	PT. ADARO INDONESIA Suite 704, World Trade Center Jl. Jend. Sudirman Kav. 31, Jakarta 12920
LOADING PORT	:	IBT Coal Terminal , Indonesia
LOADING DATES	:	December 23 to 25, 2005

Samples were drawn during loading using the mechanical sampling system at the terminal. Samples were prepared and analyzed in accordance with ASTM Standard methods with average results as follow :

Test		Result	ASTM Designation No.
Total Moisture, % wt, as received basis, ...	:	27.5	ASTM D3302
Proximate Analysis :			
- Inherent Moisture, % wt, air dried basis, ...	:	14.5	
- Ash, % wt, as received basis, ...	:	1.2	ASTM D3174
- Volatile Matter, % wt, as received basis, ...	:	37.0	ASTM D3175
- Fixed Carbon, % wt, as received basis, ...	:	34.3	
Total Sulphur, % wt, as received basis, ...	:	0.08	ASTM D3177
Gross Calorific Value, btu / lb, as received basis, ..	:	9065	ASTM D5865
Hardgrove Grindability Index	:	49	ASTM D409
Lb. SO_2 / MMBtu, (Sulphur Dioxide) dry basis, ...	:	0.19	
Sizing :			
Less than 0.25 inch ,% wt, ...	:	38.1	

Cont'd. to page .2/..

MP

PEF-CC-000307

Certificate of Analysis

ULTIMATE ANALYSIS (Dry Basis) :

- Carbon	,% wt, ...	:	72.23	ASTM D3178
- Hydrogen	,% wt, ...	:	4.13	ASTM D3178
- Nitrogen	,% wt, ...	:	0.86	ASTM D3179
- Oxygen	,% wt, ...	:	21.02	By Difference
- Sulphur	,% wt, ...	:	0.12	ASTM D3177

ASH COMPOSITION (Dry Basis) :

- SiO_2	,% wt, ...	:	32.25	ASTM D3682
- Al_2O_3	,% wt, ...	:	15.05	ASTM D3682
- Fe_2O_3	,% wt, ...	:	18.07	ASTM D3682
- CaO	,% wt, ...	:	14.08	ASTM D3682
- MgO	,% wt, ...	:	4.98	ASTM D3682
- Na_2O	,% wt, ...	:	0.47	ASTM D3682
- K_2O	,% wt, ...	:	0.97	ASTM D3682
- Mn_3O_4	,% wt, ...	:	0.24	ASTM D3682
- TiO_2	,% wt, ...	:	0.70	ASTM D3682
- P_2O_5	,% wt, ...	:	0.29	ASTM D3682
- SO_3	,% wt, ...	:	12.48	ASTM D3682

ASH FUSION TEMPERATURES :

			Reducing Atmosphere	Oxidizing Atmosphere	
- Initial Deformation (IT)	, °F, ...	:	2174	2336	ASTM D1857
- Softening (ST)	, °F, ...	:	2228	2390	ASTM D1857
- Hemispherical	, °F, ...	:	2282	2426	ASTM D1857
- Fluidity (FT)	, °F, ...	:	2336	2498	ASTM D1857

OTHER PROPERTIES (Dry Basis) :

- Mercury	, ppm, in coal	:	0.03	ASTM D6414

Cont'd to page ..3/..

PEF-CC-000308

PROGRESS Energy Florida

COAL PRODUCERS' SOLICITATION FORM
CRYSTAL RIVER 4 & 5
PAGE 1 OF 3

PRODUCER NAME: PT KIDECO JAYA AGUNG

STREET ADDRESS: MENARA MULIA SUITE 1701, 17TH FLOOR, JALAN JENDRAL GATOT SUBROTO KAV 9 – 11 JAKARTA 12930

CONTACT: MR KIM SUNG KOOK – PRESIDENT DIRECTOR OR MR. REYNARD HANOPPO – MARKETING MANAGER | TELEPHONE NO. +62 21 525 76 26

MINE(S): PASIR MINE, BATUKAJANG BOM DISTRICT: | REGENCY: PASIR REGENCY | PROVINCE : EAST KALIMANTAN

ORIGIN RAILROAD(S)/DISTRICT: EK____ CV____ Big Sandy____ Other____________ | R/R TIPPLE DESIGNATION/NUMBER:

TYPE OF LOADING FACILITY:
UNIT TRAIN: ____NA____ SINGLE CAR: __NA______ TRAINLOAD: ____NA____

MAXIMUM LOADING CAPACITY: 70,000 METRIC TONNES PER 24 HOUR
____NA____ TONS ____NA____ HOURS ____NA____ TRACK CAPACITY

WATER DELIVERY CAPABILITY: __x__ YES ____ NO IMPORT COAL: LOAD PORT ____________

SHIP THROUGH: ADANG BAY TRANSHIPMENT POINT ON MAKASSAR STRAIT, EAST KALIMANTAN LOAD RATE:: 20,000 MT/DAY SHINC GEARLESS VESSEL

TOTAL PRODUCTION CAPACITY PER MONTH: 1,600,000 METRIC TONS

PRODUCTION PER MONTH—MEETING OUR COAL SPECIFICATIONS: 1,200,0000 METRIC TONS

TYPE OF MINE: ______% DEEP ______% STRIP ______% AUGER

SEAMS: MULTIPLE SEAMS OF 10 – 20 SEAMS WITH THICKNESS OF SEAMS BETWEEN 6 TO 60 METRES | BLEND RATIOS: NA

COAL PREPARATION: ___X___ RAW ______ WASHED ______ COMBINATION

TYPE OF COAL WASHER, IF WASHED:

TYPE OF COAL SAMPLING: MECHANICAL TWO-STAGE CROSS-BELT COAL SAMPLER ON THE BARGE LOADER CONVEYOR BELT PRODUCED BY SGS AUSTRALIA AND BIAS-TESTED BY SGS AUSTRALIA AND PT SUCOFINDO (INDONESIAN CORRESPONDENCE OF SGS)

TYPE OF LABOR CONTRACT(S): RENEGOTIATED EVERY 3 YEARS | DATE FOR RENEGOTIATION: PART OF SUBCONTRACTORS CONTRACT – REGENEGOTIATED EVERY 3 YEARS

TYPE OF COAL WEIGHING: VESSEL DRAFT SURVEY | SCALE CERTIFIED? ____YES ____ NO

PERIOD	TONNAGE	BASE PRICE PER TON DES IMT
2007 – 2009	500,000 ST/YEAR (7 x 71,600 ST) +/- 10% FES	2007: $44.50/ST; 2008: $45.25/ST; 2009: $45.75/ST DES

IF THIS COAL IS OFFERED BY A COMPANY OR INDIVIDUAL WHICH IS NOT THE PRODUCER PLEASE INDICATE SO BY MAKING AN "X" IN THIS SPOT.

PRODUCER'S COMMENTS: KIDECO IS INDONESIA'S THIRD LARGEST COAL MINE PRODUCTING 18.2 MILLION METRIC TONNES OF STEAM COAL IN 2005 AND PLANNED FOR 18.5 MILLION METRIC TONNES OF STEAM COAL IN 2006. PLEASE SEE ATTACHMENT 3.

CREDIT REFERENCES (Minimum two): CITIBANK NA JAKARTA OFFICE, KOREA EXCHANGE BANK JAKARTA OFFICE

INDUSTRY REFERENCES (Minimum four): ENEL TRADE SPA (ITALY) , EDF TRADING LTD (UK), SSM COAL AMERICAS LLC (US), TAIWAN POWER COMPANY (TAIWAN ROC)

SIGNATURE: | TITLE: | DATE:

MAIL THIS FORM AND ANY ADDITIONAL INFORMATION TO:
Ms. Annette Britton
annette.britton@pgnmail.com
c/o Progress Energy Carolinas, Inc. Regulated Fuels Department
410 S. Wilmington Street
Mail Code PEB10
Raleigh, NC 27601

PROGRESS Energy Florida

COAL PRODUCERS' SOLICITATION F
CRYSTAL RIVER 4 & 5
PAGE 2 OF 3

DESCRIPTION	OFFERED COAL SPECIFICATIONS		REQUIRED COAL SPECIFICATIONS	
	"AS RECEIVED" AVERAGE OR TYPICAL	"AS RECEIVED" GUARANTEED	BITUMINOUS "AS RECEIVED" GUARANTEED	SUB-BITUMINOUS "AS RECEIVED" GUARANTEED
MOISTURE (TOTAL) %	27	MIN 26 – MAX 30 [4]	8.0% MAX.	30.0% MAX.
SURFACE MOISTURE %			5.0% MAX.	5.0% MAX.
ASH %	3.0	MIN 2.8 – MAX 4.0 [4]	10.0% MAX.[2]	7.8% MAX.[2]
TOTAL SULFUR %	0.10	MIN 0.08 – MAX 0.15 [4]	1.2 LB/MAX.[1]	1.2 LB/MAX.[1]
BTU/LB GROSS AS RECEIVED	8,700	8,200 MIN	12,300 MIN.	8,200/LB MIN.
ASH SOFTENING DEGREES FAHRENHEIT H=W (R)	2,080	MIN 2,048 – MAX 2,156 [4]	2,500 MIN.	2,200 MIN.
VOLATILE %	36.0	MIN 35.0 – MAX 43.0 [4]	31.0% MIN.[1]	31.0% MIN.[1]
GRINDABILITY, HARDGROVE	46	MIN 44 – MAX 47 [4]	42 MIN.[3]	65 MIN.[3]
SIZE	2 x 0		2" X 0"	2" X 0"
FINES (-1/4" X 0")	30	28 – 35	45% MAX.[5]	30% MAX.[5]
PYRITIC SULFUR			0.2% MAX.[1]	0.2% MAX.[1]
FIXED CARBON %	BY DIFFERENCE – ASTM		——	——
HYDROGEN %	3.30	MAX 10.00	——	——
NITROGEN %	0.56	MAX 3.00	——	——
,HLORINE %	< 100PPM	< 100PPM	——	——
OXYGEN %	17.02	MAX 25.00	——	——

[1]Must be met on an individual shipment basis.
[2]Adjustable in direct proportion to Btu.
[3]Adjustable in inverse proportion to Btu.
[4]Economic analyses will be based on these values.
[5]Preferred value, coals not meeting this specification will be considered.

MINERAL ANALYSIS %WEIGHT ON DRY BASIS			TRACE ELEMENTS PPM IN COAL		
DESCRIPTION	AVERAGE	STD. DEV.	DESCRIPTION	AVERAGE	STD DEV.
P_2O_5	0.68		Antimony		
SiO_2	32.24		Arsenic		
Fe_2O_3	21.14		Beryllium		
Al_2O_3	11.70		Cadmium		
TiO_2	0.89		Chromium		
CaO	16.35		Cobalt		
MgO	7.83		Fluorine	<100PPM	
SO_3	8.14		Lead		
K_2O	0.49		Lithium		
Na_2O	0.11	1 MAX	Manganese		
Undetermined			Mercury		
Base/Acid Ratio			Nickel		
ıaximum Base/Acid Ratio			Selenium	<100PPM	

*NOTE: ADD SHEETS IF MORE THAN ONE SEAM

ATTACHMENT 3

This offer of Indonesian coal is subject to mutual agreement on SSM's general terms and conditions.

1. QUANTITY
   The offered tonnage is comprised of seven (7) Panamax gearless cargoes per year of ~~71,600 ST +/- 10% seller~~'s option each with guaranteed ~~discharge rate~~ at IMT of 20,000 MT/DAY SHINC. Shipment period beginning in 2007 and ending in ~~2009 fairly evenly spread~~.

2. PRICE
   The offered price is $44.50 per short ton for shipments in 2007, $45.25 per short ton for shipments in 2008, and $45.75 per short ton for shipments in 2009 DES IMT, Mississippi River, and firm until February 22, 2006.

3. PREMIUM/PENALTY
   The contract price will be adjusted on a prorata basis if actual heating value is over/under 8,700 Btu/lb gross as received.

4. WEIGHT DETERMINATION
   Draft survey of vessel at loadport by independent surveyor to be final and binding to both parties. Cost for Seller's account.

5. QUALITY DETERMINATION
   At loadport in accordance with ASTM standards by an independent laboratory for Seller's account.

6. PAYMENT
   Telegraphically within 25 banking days after B/L-date, subject to credit approval.

7. DISCHARGING RATE
   20,000 MT/DAY SHINC.

8. DEMURRAGE/DESPATCH
   As per Seller's contract of Affreightment.

9. CREDIT
   Subject to SSM credit department approval.

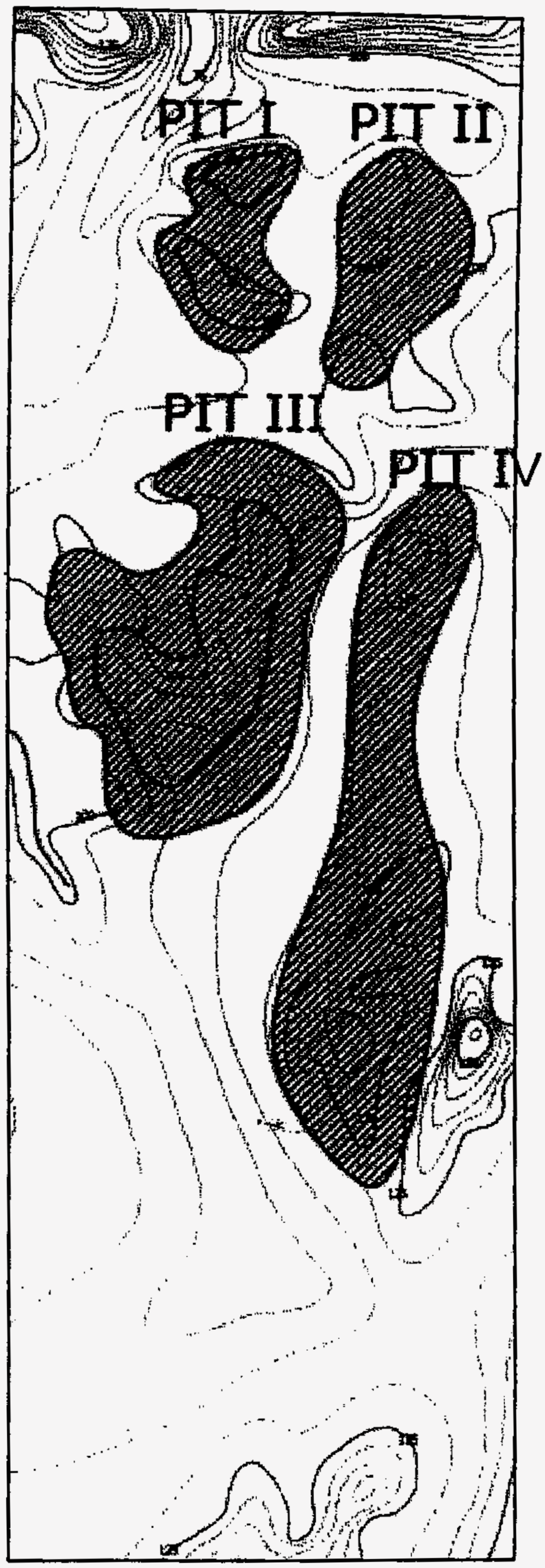
Commonwealth Coal
SERVICES, INC.

KIMCO ARMINDO

Sukamaju Coal

Parameter	Units	Typical	Range(Min/Max)
Calorific Value			
GAD	kcal/kg	6,200	6,100 Min
GAR	kcal/kg	5,800	5,700 Min
NAR	kcal/kg	5,550	5,400 Min
Total moisture	%	18	21.0 Max
Proximate Analysis (air dried)			
Inherent moisture	%	12.3	14.0 Max
Ash	%	7	9.0 Max
Volatile matter	%	40	35.0 Min
Total Sulfur	%	0.45	0.55 Max
Phosphorus	%	0.002	
Chlorine	%	0.01	
Physical Properties			
Hardgrove Index	HGI	47	45 Min
Size	% above 50mm	0	0 Max
	% under 2mm	25	30 Max
Ash Fusion Temperture (Reducing atmosphere)			
Deformation	℃	1,200	1,150 Min
Ultimate Analysis (dry basis)			
Carbon	%	70	
Hydrogen	%	4	
Nitrogen	%	1.2	1.5 Max
Oxygen	%	24.8	
Ash Analysis (dry basis)			
Fe_2O_3	%	13	
Na_2O	%	0.5	
K_2O	%	1	
CaO	%	10	

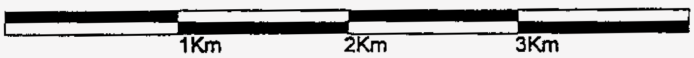
PT Kimco Armindo Coal Reserves



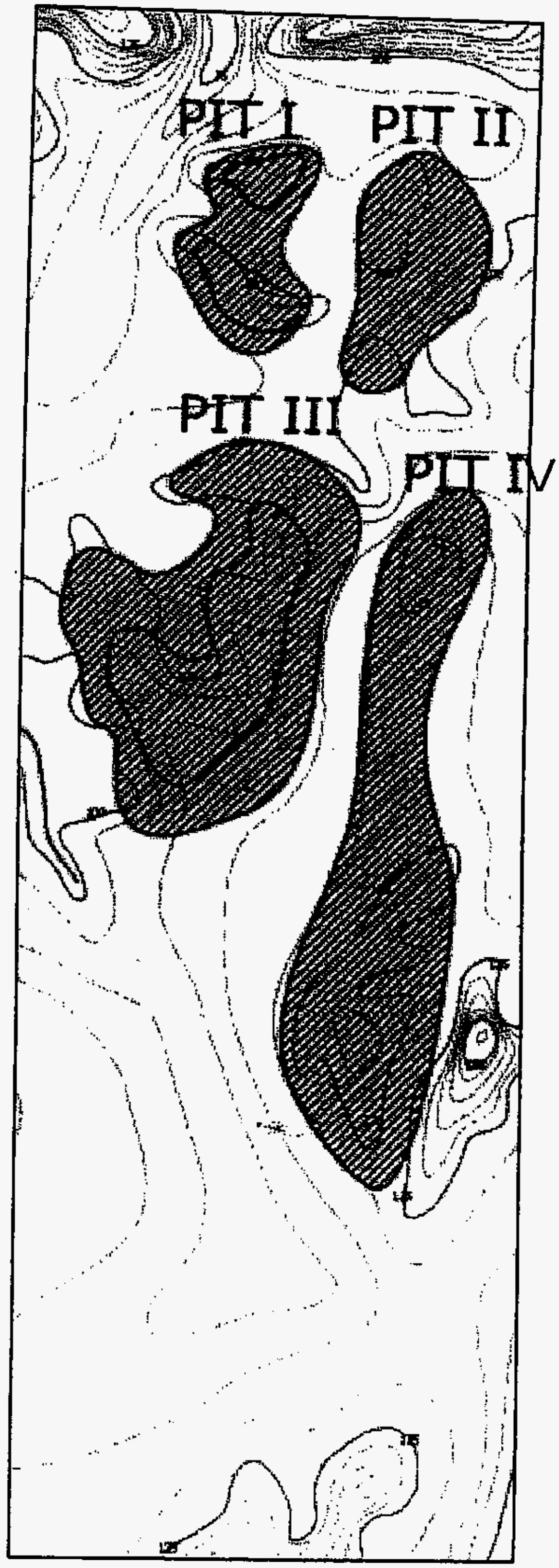
Saleable Coal Reserves
- Pit I: 16 million tons
- Pit II: 8 million tons
- Pit III: 35 million tons
- Pit IV: 21 million tons

Total: 80 million tons

Commonwealth Coal
SERVICES, INC.



PT Kimco Armindo Stripping Ratio



Overburden Ratio

- Pit I: 3:1
- Pit II: 3:1
- Pit III: 5:1
- Pit IV: 5:1

Commonwealth Coal
SERVICES, INC.

N

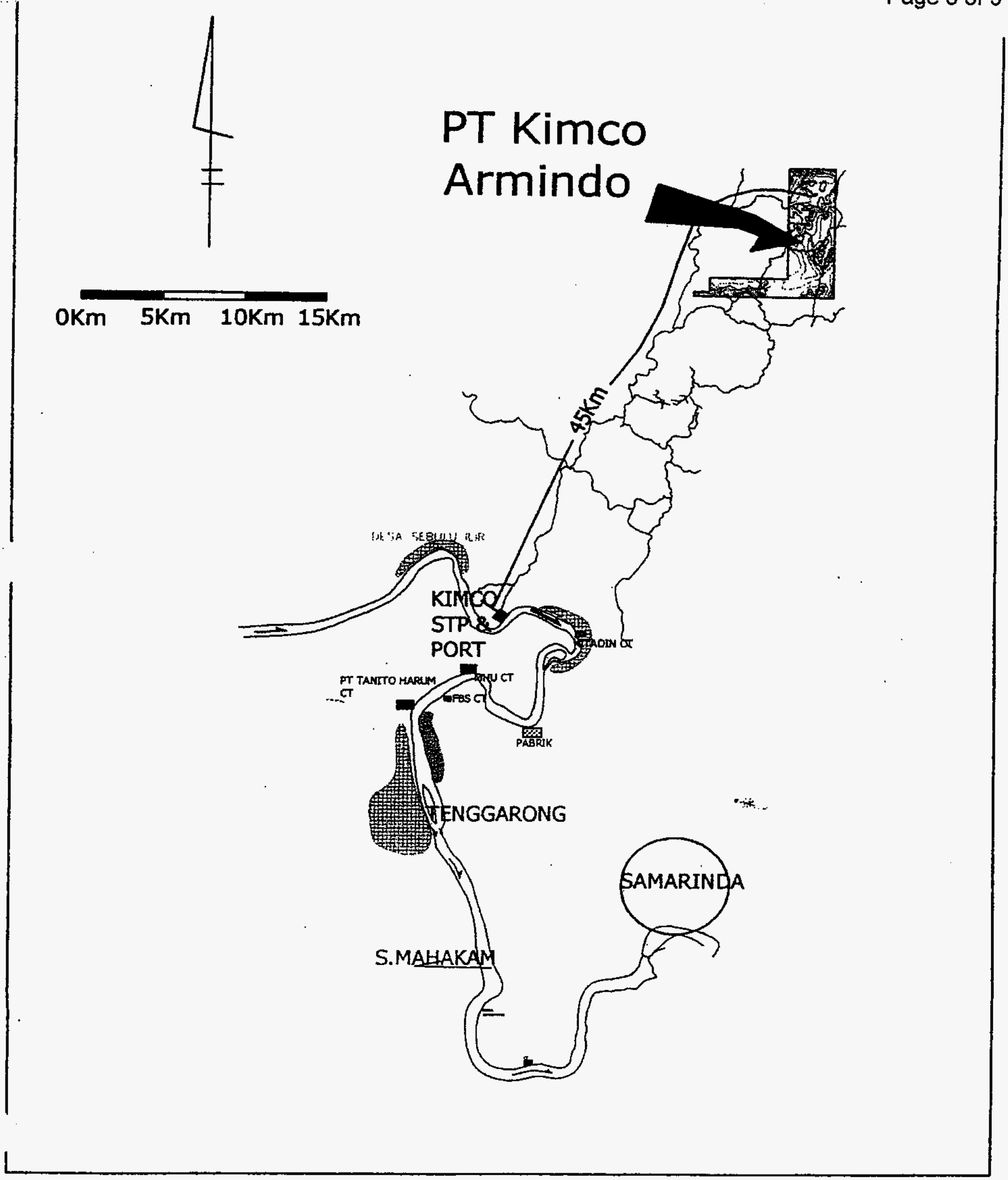
1Km 2Km 3Km

PT Kimco Armindo Mining Plan

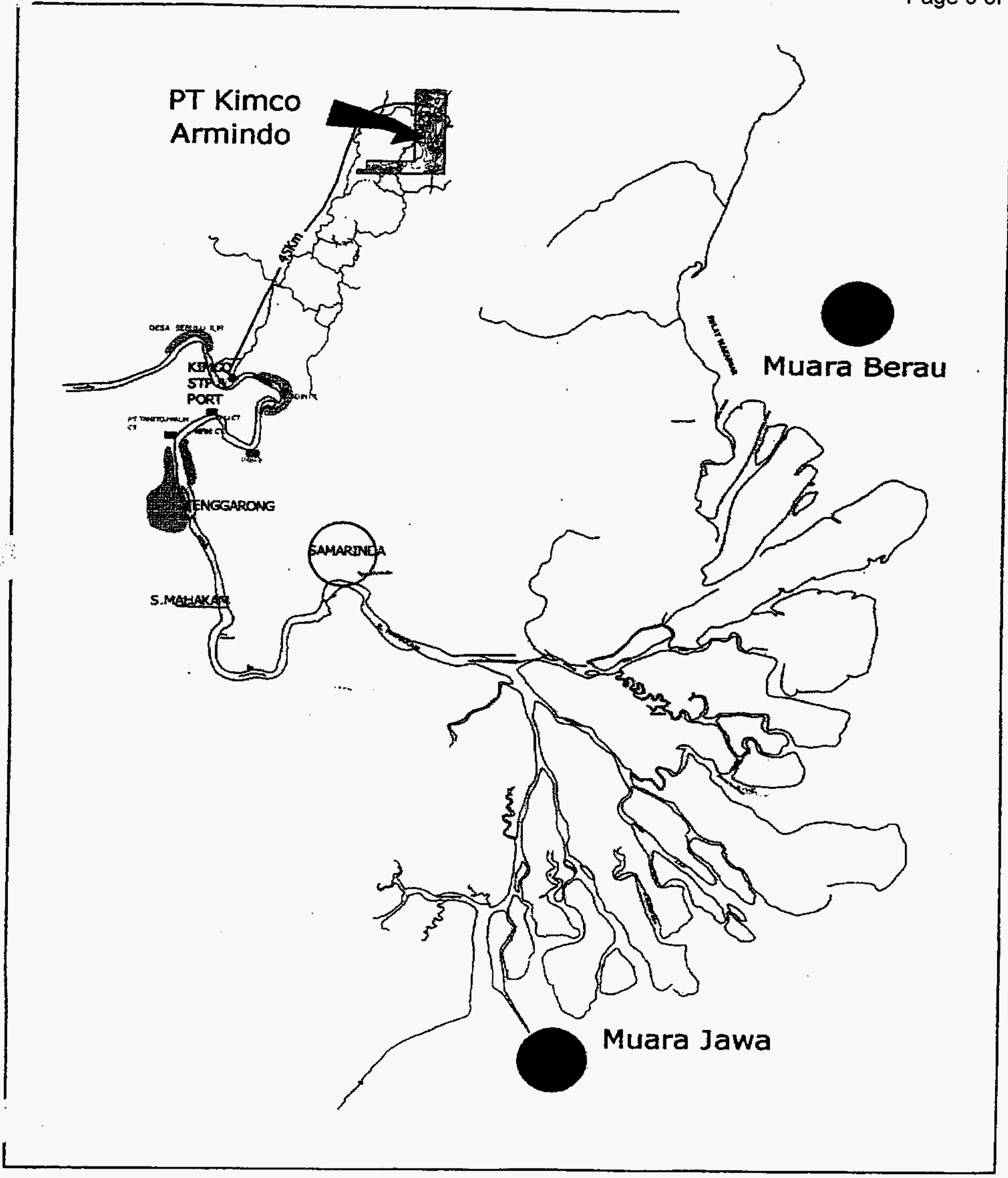
Mining Plan by Year
- 2005: Pit III
- 2006: Pit III
- 2007: Pit I
- 2007 – 2010: Pit I, II, III
- >2010: Pit I, II, III, IV

Commonwealth Coal
SERVICES, INC.

Kimco Shipping
Mine to River Terminal



Kimco Shipping
Mine to Vessel



DOCKET 070703 – EI
Progress Energy Florida
Exhibit No.: ______ (JS-4)
Page 1 of 4

COALTRADE

Phone 314.342.7600

COAL CONFIRMATION LETTER

Trade Ref #: 980-4949

March 10, 2004

Al Pitcher
Progress Fuels Corporation
One Progress Plaza 200 Central Ave
St. Petersburg, FL 33701

xc: AKOP DHD FHL MJR THH VMH LSW RFP

Dear Al:

This letter confirms the agreement between Peabody COALTRADE, Inc. ("PCT") and Progress Fuels Corporation ("Progress") with respect to the Transaction dated March 09, 2004 described below and constitutes a "Confirmation."

TRANSACTION TYPE:	Physical
PRODUCT	Sub-Bituminous Coal, PRB 8800
BUYER:	Progress Fuels Corporation
SELLER:	Peabody COALTRADE, Inc.
BUYER'S CONTACT:	Al Pitcher (727) 824-6693 / FAX: (727)824-6601
SELLER'S CONTACT:	Bill Grebenc (314) 342-7598 / FAX: (314) 588-2702
TERM:	March 01, 2004 - April 29, 2004
QUANTITY:	29,000 tons total
SCHEDULE:	1 Train(s) per month, approximately 14,500 tons each
PRICE:	$[illegible] per ton
PAYMENT TERMS:	Payment shall be made by the 25th day of the delivery month for financial settlements or 15 days after receipt of invoice for physical deliveries.
INVOICES:	Seller shall submit an invoice for coal delivered during the preceding month to Buyer in a form acceptable to the Parties on or before the fifteenth day of each month.

Name
Address:

Fax:
Attn:

MAR. 16. 2004 2:12PM PEABODY ENERGY COAL

DELIVERY POINT: FOB barge at Cahokia Terminal, Cahokia, IL.

SOURCE: Peabody North Antelope / Rochelle Mine

Mine to be designated by Seller no later than 20 days in advance of the first day of each month.

SPECIFICATION: Typical as-received basis in accordance with ASTM standards for each shipment in a month, as follows:

Quality Type [Units]	Typical	Min / Max Value	~~Premium-Penalty~~	Reject
Ash	5.50 %	NONE	NONE	NONE
BTU	8,800.00 Btu/lb.	NONE	Premium / Penalty	< 8,600.00 Btu/lb.
Moisture	27.00 %	NONE	NONE	NONE
lbSO2/MMBTU	0.55	NONE	Premium / Penalty	> 1.20

Commodity Buyer may reject any shipment falling outside of the aforementioned specifications for Btu/lb (min) and Sulfur (max) with written notification to Commodity Seller. Commodity Seller shall remove rejected coal at Commodity Seller's cost. Commodity Seller shall be required to replace the rejected coal no later than the last calendar day of the delivery month.

QUALITY PRICE ADJUSTMENTS: BTU Adjustment. The price will be adjusted to reflect actual caloric value received according to the following formula:

Price x [(Actual Btu/lb. - guaranteed Btu/lb.) / guaranteed Btu/lb.]

SO2 Adjustment: If it is determined that the monthly weighted average pounds of SO2/MMBtu (computed to the nearest 0.01 of a point of SO2) on an as received basis for shipments accepted by Buyer for any month is other than the typical SO2/MMBtu, Buyer shall calculate a premium or penalty based on a relevant number of SO2 allowances for each month as follows:

Price Adjustment ($/ton of Coal) =
(Typical SO2/MMBtu - Actual Lbs SO2/MMBtu) * Actual Btu/lb * E / 1,000,000

Where E is the average price of SO2 allowances expressed in dollars per ton of SO2.
The average price of SO2 allowances shall be based on the monthly weighted average of AIR DAILY EA prices for the respective month in which shipments occurred. The adjustment will be calculated monthly and shall be settled financially.

SAMPLING: Sampling, via mechanical sampler, for each shipment shall be performed at the Delivery Point with the cost for such sampling for Seller's account.

ANALYSIS: Analysis shall be performed in accordance with ASTM standards by a mutually acceptable independent commercial laboratory appointed by Seller. Cost for such analysis shall be for Seller's account. [illegible]

SPECIAL PROVISIONS: Test burn NARM ($37.35) FOB Mine Plus $12.56 rail rate/thruput = $49.91

If this Confirmation correctly sets forth the terms and conditions of this Transaction that we have entered into, please promptly confirm in a reply to us by signing below and sending this Confirmation (or a copy hereof) to us by fax (314) 588-2702 within three (3) business days of receipt of this Confirmation.

If Counterparty objects to any differences between the binding agreement of the parties regarding this Transaction and the contents of the Confirmation. Counterparty must notify Peabody COALTRADE, Inc. of its objections in writing by fax (314) 588-2702 within such time period.

If Counterparty fails to so reply or object within such time period. such objections shall be deemed waived and the terms of this Confirmation will become final and conclusive evidence of all the terms of the binding agreement regarding this Transaction. Any other terms and conditions are objected to and shall not be binding upon PCT.

This Confirmation supersedes and replaces any broker confirmation(s) regarding this Transaction to the extent of any irreconcilable conflict. If Counterparty notifies PCT of additional or different terms from those set forth herein, those terms shall be construed as proposals for amendments to this Transaction and shall not become part hereof unless agreed to by PCT in a supplemental written confirmation.

If you are in agreement with the foregoing, please execute where indicated below and fax a copy of this letter to COALTRADE Scheduling at (314) 588-2702.

Sincerely,

Peabody COALTRADE, Inc.

By: Bill Grobene
Bill Grobene

Title: Trader

Date: March 10, 2004

AGREED TO AND ACCEPTED BY

Progress Fuels Corporation

By:

Title: Vice President - Coal Procurement

QUALITY SUMMARY AS OF 11/18/2003

Peabody / Bluegrass / Black Beauty

All Analysis on As Received Basis

Analysis may change due to changes in mine plan or prepration intended for informational purposes only

MINE	MOISTURE	ASH	V.M.	F.C.	Btu	SULFUR	lb.s SO2/ mmBtu	AFT (H=W)*	Chlorine	Grind	% -1/4"	Remarks
Big Mountain	6.0	13.2	31.9	48.9	12,150	0.72	1.18	+2700	0.15	43	32.4	Typical
Cook Mountain	5.0	13.1	31.4	50.5	12,345	0.63	1.02	+2700	0.15	42	n/a	Typical
Federal No.2												
Raw	5.2	15.5	33.2	46.1	12,025	2.65	4.40	2210	0.08	54	44.5	Typical
Washed	5.4	6.8	36.5	51.3	13,350	2.09	3.13	2240	0.10	55	50.7	Typical
Rocklick												
Eagle - Met	7.3	5.5	28.7	58.5	13,609	0.87	1.28	+2700	0.20	65	50.4	Typical
Winifrede (W/R)	7.0	10.9	31.3	50.8	12,500	0.79	1.26	+2700	0.16	50	47.3	Typical
Wells												
Powellton - Met	6.8	5.4	33.2	54.6	13,550	0.81	1.19	+2700	0.23	52	51.4	Typical
No.2 Gas/Powellton (W/R)	6.6	10.5	31.6	51.3	12,700	0.82	1.29	2650	0.20	50	51.4	Typical
Marissa 6 Washed	13.8	10.3	34.6	41.3	10,778	2.93	5.43	2105	0.09	53	58.0	Randolph Prep
Willow Lake 5&6 W (Arclar)	9.2	8.2	36.0	46.6	12,171	2.88	4.73	2085	0.20	54	n/a	Typical
Willow Lake 5W (Arclar)	9.2	8.7	36.1	46.0	12,054	2.78	4.61	2070	0.25	55	n/a	Typical
Cottage Grove 6W (Arclar)	9.4	7.1	36.2	47.3	12,296	2.42	3.93	2075	0.17	54	n/a	Typical
Cottage Grove TOP6W (Arclar)	9.0	6.2	35.5	49.3	12,480	2.21	3.54	2070	0.16	53	n/a	Typical
Cottage Grove TOP6R (Arclar)	8.0	10.2	34.9	46.9	11,998	3.50	5.83	1990	0.15	53	n/a	Typical
Hawthorn 6&7 Washed	14.0	10.1	33.8	42.1	11,013	1.95	3.54	2195	0.04	55	n/a	Last year of production
Lynnville 5 Washed	13.8	9.8	34.4	42.0	10,974	3.25	5.92	2145	0.02	56	n/a	Last year of production
Camp Prep 9 Washed	12.5	8.8	35.4	43.3	11,269	2.83	5.02	2070	0.14	54	45.9	Typical
Seneca	13.8	9.8	33.4	43.0	10,350	0.45	0.87	2695	0.01	43	n/a	Current Production
Big Sky	26.4	8.8	28.3	36.5	8,650	0.75	1.73	2215	0.01	65	n/a	Current Production
Black Mesa	13.1	8.8	36.5	41.6	10,663	0.42	0.79	2265	0.01	44	35.0	Current Production
Kayenta	12.3	9.1	36.6	42.0	10,730	0.51	0.95	2280	0.01	46	35.0	Current Production
Lee Ranch	15.5	17.7	33.2	33.6	9,230	0.88	1.91	2450	0.01	51	40.0	Typical
Caballo	29.9	4.8	31.5	33.8	8,500	0.38	0.89	2135	0.01	73	30.7	Typical
Rochell/North Antelope												
West Pit	26.4	4.8	32.4	36.4	8,910	0.21	0.47	2130	<0.01	63	25.4	Typical
Middle Pit	26.7	4.2	32.5	36.6	8,946	0.20	0.45	2130	<0.01	64	25.4	Typical
North Pit	27.0	4.3	32.6	36.1	8,886	0.20	0.45	2130	<0.01	65	25.4	Typical
East Pit	29.0	4.5	32.0	34.5	8,525	0.22	0.52	2145	<0.01	66	25.4	Typical
8800btu Mid/N/E Pit	26.9	4.4	32.4	36.3	8,800	0.20	0.45	2130	<0.01	64	25.4	Typical
Rawhide	31.0	4.9	29.9	34.2	8,300	0.33	0.79	2160	<0.01	80	30.6	Typical

SGS

May 12, 2006

PEABODY ENERGY COAL SALES
701 MARKET STREET
SUITE 700
ST. LOUIS MO 63101

Sample identification by
SGS

Barge No. PEN 210
Trench Top Sample

Kind of sample reported to us: Coal

Sample taken at: Cook Coal Terminal

Sample taken by: SGS

Date sampled: May 4, 2006

Date received: May 4, 2006

Analysis Report No. 63-109827

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	28.04	xxxxx
% Ash	6.58	9.14
% Volatile	31.04	43.13
% Fixed Carbon	34.34	47.73
	100.00	100.00
Btu/lb	8574	11915
% Sulfur	0.40	0.55
MAF Btu		13114
Alk. as Sodium Oxide	0.09	0.13

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	28.04	xxxxx
% Carbon	49.75	69.13
% Hydrogen	3.57	4.96
% Nitrogen	0.65	0.91
% Sulfur	0.40	0.55
% Ash	6.58	9.14
% Oxygen(diff)	11.01	15.31
	100.00	100.00

FUSION TEMPERATURE OF ASH, (oF)

	Reducing	Oxidizing
Initial Deformation (IT)	2150	2230
Softening (ST)	2200	2300
Hemispherical (HT)	2230	2340
Fluid (FT)	2370	2470

MEMBER ACIL

Respectfully Submitted,
SGS NORTH AMERICA, INC.
SIGNATURE ON FILE
Henderson Laboratory

SGS North America Inc | Minerals Services Division
PO Box 752, Henderson, KY 42419 (270) 827-1187 f (270) 826-0719 www.us.sgs.com/minerals

SGS

May 12, 2006

PEABODY ENERGY COAL SALES
701 MARKET STREET
SUITE 700
ST. LOUIS MO 63101

Sample identification by
SGS

Barge No. PEN 210
Trench Top Sample

Kind of sample reported to us	Coal
Sample taken at	Cook Coal Terminal
Sample taken by	SGS
Date sampled	May 4, 2006
Date received	May 4, 2006

Analysis report no. 63-109827

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	41.60
Aluminum oxide	17.26
Titanium dioxide	1.14
Iron oxide	6.12
Calcium oxide	14.48
Magnesium oxide	3.02
Potassium oxide	0.73
Sodium oxide	0.95
Sulfur trioxide	15.06
Phosphorus pentoxide	0.62
Strontium oxide	0.21
Barium oxide	0.43
Manganese oxide	0.01
Undetermined	- 1.63
	100.00

Silica Value = 63.78
Base:Acid Ratio = 0.42
T250 Temperature = 2385

Type of Ash = LIGNITIC
Fouling Index = 0.95

MEMBER ACIL

Respectfully Submitted,
SGS NORTH AMERICA, INC
SIGNATURE ON FILE
Henderson Laboratory

SGS

May 12, 2006

PEABODY ENERGY COAL SALES
701 MARKET STREET
SUITE 700
ST. LOUIS MO 63101

Sample identification by
SGS

Barge No. H 9268
Trench Top Sample

Kind of sample reported to us: Coal

Sample taken at: Cook Coal Terminal

Sample taken by: SGS

Date sampled: May 4, 2006

Date received: May 4, 2006

Analysis Report No. 63-109828

PROXIMATE ANALYSIS	As Received	Dry Basis	ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	27.62	xxxxx	% Moisture	27.62	xxxxx
% Ash	6.73	9.30	% Carbon	50.12	69.24
% Volatile	31.62	43.69	% Hydrogen	3.60	4.98
% Fixed Carbon	34.03	47.01	% Nitrogen	0.67	0.93
	100.00	100.00	% Sulfur	0.43	0.59
			% Ash	6.73	9.30
Btu/lb	8597	11877	% Oxygen(diff)	10.83	14.96
% Sulfur	0.43	0.59		100.00	100.00
MAF Btu		13095			
Alk. as Sodium Oxide	0.10	0.13			

FUSION TEMPERATURE OF ASH, (oF)

	Reducing	Oxidizing
Initial Deformation (IT)	2140	2210
Softening (ST)	2170	2240
Hemispherical (HT)	2190	2275
Fluid (FT)	2220	2320

MEMBER ACIL

Respectfully Submitted,
SGS NORTH AMERICA, INC.
SIGNATURE ON FILE
Henderson Laboratory

SGS

May 12, 2006

PEABODY ENERGY COAL SALES
701 MARKET STREET
SUITE 700
ST. LOUIS MO 63101

Sample identification by
SGS

Barge No. H 9268
Trench Top Sample

Kind of sample reported to us	Coal
Sample taken at	Cook Coal Terminal
Sample taken by	SGS
Date sampled	May 4, 2006
Date received	May 4, 2006

Analysis report no. 63-109828

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	41.46
Aluminum oxide	17.28
Titanium dioxide	1.20
Iron oxide	7.00
Calcium oxide	15.45
Magnesium oxide	3.17
Potassium oxide	0.73
Sodium oxide	0.96
Sulfur trioxide	13.37
Phosphorus pentoxide	0.67
Strontium oxide	0.22
Barium oxide	0.45
Manganese oxide	0.01
Undetermined	- 1.97
	100.00

Silica Value = 61.81
Base:Acid Ratio = 0.46
T250 Temperature = 2350

Type of Ash = LIGNITIC
Fouling Index = 0.96

MEMBER ACIL

Respectfully Submitted,
SGS NORTH AMERICA, INC.
SIGNATURE ON FILE
Henderson Laboratory

STANDARD LABORATORIES, INC.

10/02/06

CUSTOMER: ARCH COAL, INC.

BLACK THUNDER NORTH 2ND QUARTER 2006 COMPOSITE

JOB NO.: 200601997001
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	26.38		25.33
ASH	5.53	7.51	
VOLATILE	32.71	44.43	
FIXED C	35.38	48.06	
SULFUR	0.28	0.38	
BTU/#	8898	12087	
		13068	

EQ MOISTURE 25.33

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	26.38		25.33
ASH	5.53	7.51	
SULFUR	0.28	0.38	
NITROGEN	0.66	0.89	
CARBON	52.32	71.07	
HYDROGEN	3.48	4.73	
OXYGEN	11.35	15.42	

MINERAL ANALYSIS OF ASH (%)

PHOSPHORUS PENTOXIDE	0.95
SILICON DIOXIDE	38.77
FERRIC OXIDE	5.55
ALUMINUM OXIDE	16.67
TITANIUM DIOXIDE	1.06
MANGANESE DIOXIDE	0.04
CALCIUM OXIDE	19.59
MAGNESIUM OXIDE	3.68
POTASSIUM OXIDE	0.52
SODIUM OXIDE	1.18
SULFUR TRIOXIDE	7.81
BARIUM OXIDE	0.53
STRONTIUM	0.22
UNDETERMINED	3.43

FORMS OF SULFUR (%)

	AS RECD	DRY
SULFATE	0.01	0.01
PYRITIC	0.07	0.09
ORGANIC	0.21	0.28

FUSION TEMPERATURE OF ASH (F)

	OXIDIZING	REDUCING
INITIAL	2230	2140
SOFTENING	2260	2155
HEMISPHERICAL	2270	2165
FLUID	2350	2260

ADDITIONAL DATA

AIR DRY LOSS		12.64
LBS H20/MM BTU		29.65
LBS ASH/MM BTU		6.21
LBS SULFUR/MM BTU		0.31
BASE/ACID RATIO		0.54
T250	2283 DEG F	
% ALKALI AS Na2O		0.11
SPECIFIC GRAVITY		
FREE SWELLING INDEX		0.0

GRINDABILITY (HGI)

HGI 57.00
AT 15.91 % MOISTURE

WATER SOLUBLE ALKALIES (%)

	AS RECD	DRY
SODIUM OXIDE	0.065	0.088
POTASSIUM OXIDE	0.005	0.007

DOCKET 070703 – EI
Progress Energy Florida
Exhibit No.: ____ (JS-5)
Page 5 of 7

STANDARD LABORATORIES, INC.

10/02/06

CUSTOMER: ARCH COAL, INC.

JOB NO.: 200601997001
LOCATION: CASPER, WY
APPROVAL:

SAMPLE ID: BLACK THUNDER NORTH 2ND QUARTER 2006 COMPOSITE

TRACE ELEMENT, DRY BASIS			RESULT
ANTIMONY	Sb	PPM	0.13
ARSENIC	As	PPM	1.2
BARIUM	Ba	PPM	357
BERYLLIUM	Be	PPM	0.2
BORON	B	PPM	41
BROMINE	Br	PPM	4
CADMIUM	Cd	PPM	0.09
CHLORINE	Cl	PPM	8
CHROMIUM	Cr	PPM	5
COBALT	Co	PPM	2.0
COPPER	Cu	PPM	9
FLUORINE	F	PPM	104.2
LEAD	Pb	PPM	2.0
LITHIUM	Li	PPM	2.4
MANGANESE	Mn	PPM	19
MERCURY	Hg	PPM	0.110
MOLYBDENUM	Mo	PPM	0.6
NICKEL	Ni	PPM	4
SELENIUM	Se	PPM	0.7
SILVER	Ag	PPM	0.10
STRONTIUM	Sr	PPM	140
THALLIUM	Tl	PPM	0.07
TIN	Sn	PPM	0.3
URANIUM	U	PPM	0.5
VANADIUM	V	PPM	13
ZINC	Zn	PPM	12
ZIRCONIUM	Zr	PPM	13.3

Black Thunder Mine	2000						2002									2006		
	May	July	Sept.	Oct.	Nov.		09/29/02	09/11/02	09/10/02	09/08/02	09/01/02	10/07/02	11/02/02	11/01/02		May	May	
Lab Number	44-39970	44-39971	44-39973	44-39974	44-39976	Average	4457929	4457930	4457931	4457932	4457933	4457934	4457935	4457936	Average	63-109827	63-109828	Average
Proximate Analysis																		
Total Moisture	26.94	27.24	27.00	27.34	27.33	27.28	27.39	27.20	27.03	26.95	27.15	27.11	27.62	27.31	27.22	28.04	27.62	27.83
Ash	7.86	7.54	8.13	7.21	7.31	7.69	7.23	7.27	6.99	6.97	7.83	8.53	5.98	8.57	7.40	9.14	9.30	9.22
Volatile Matter	43.08	42.90	42.69	43.02	43.15	43.09										43.13	43.69	43.41
Fixed Carbon	49.06	49.56	49.16	49.77	49.54	48.64										47.73	47.01	47.37
MAF Fixed Carbon	53.25	53.60	53.53	53.64	53.45	53.12										52.53	51.83	52.18
BTU	12044	12046	12040	12138	12163	12039	12071	12056	12036	12036	11965	11925	12292	11955	12045	11915	11877	11896
MAFBTU	13071	13026	13105	13081	13122	13042	13012	13001	12941	12937	12976	13037	13074	13078	13007	13114	13095	13104
Sulfur	0.41	0.40	0.44	0.43	0.48	0.41	0.34	0.32	0.37	0.38	0.38	0.46	0.33	0.36	0.37	0.55	0.59	0.57
lb.SO2/mmBtu	0.68	0.66	0.73	0.71	0.79	0.78										0.92	0.99	0.96
Ultimate Analysis (Dry)																		
Carbon	70.08	69.63	69.39	70.19	70.16	69.74							71.15	68.58	69.87	69.13	69.24	69.19
Hydrogen	5.07	4.93	4.98	5.01	4.99	5.19							5.66	5.65	5.66	4.96	4.98	4.97
Nitrogen	0.93	0.90	0.95	0.96	0.97	0.94							0.98	0.95	0.97	0.91	0.93	0.92
Chlorine	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	0.01												
Sulfur	0.41	0.40	0.44	0.43	0.48	0.43							0.33	0.36	0.34	0.55	0.59	0.57
Ash	7.86	7.54	8.13	7.21	7.31	7.83							5.98	8.57	7.28	9.14	9.30	9.22
Oxygen	15.65	16.60	16.11	16.20	16.09	15.66							15.90	15.89	15.90	15.31	14.96	15.14
Total	100.01	100.01	100.01	100.01	100.01								100.00	100.00		100.00	100.00	
Maf-Carbon	76.40	75.64	75.89	76.00	76.09	76.03							75.95	75.30	75.62	76.55	76.84	76.69
Maf-Hydrogen	5.53	5.36	5.45	5.42	5.41	5.66							6.04	6.20	6.12	5.49	5.53	5.51
Maf-Nitrogen	1.01	0.98	1.04	1.04	1.05	1.03							1.05	1.04	1.04	1.01	1.03	1.02
Maf-Chlorine	0.01	0.01	0.01	0.01	0.01	0.01							0.00	0.00	0.00	0.00	0.00	0.00
Maf-Oxygen	17.06	18.03	17.62	17.54	17.45	17.29							16.97	17.45	17.21	16.95	16.60	16.78
Total	100.01	100.01	100.01	100.01	100.01								100.00	100.00		100.00	100.00	
Sulfur Forms (Dry)																		
Pyritic	0.04	0.05	0.09	0.07	0.08	0.07												
Sulfate	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	0.01												
Organic	0.37	0.35	0.35	0.36	0.40	0.37												
Ash Fusion																		
Reducing Atmosphere																		
Initial Deformation (I.D.)	2145	2144	2156	2117	2144	2139	2126	2130	2110	2122	2158	2178	2112	2162	2137	2160	2140	2145
Softening (H=W)	2157	2155	2164	2124	2152	2153	2136	2139	2120	2134	2169	2189	2122	2173	2148	2200	2170	2185
Hemispherical (H=1/2W)	2168	2160	2176	2131	2161	2165	2146	2148	2130	2145	2181	2199	2131	2183	2158	2230	2190	2210
Fluid	2181	2168	2200	2142	2167	2185	2156	2160	2141	2157	2191	2210	2140	2195	2169	2370	2220	2295
Oxidizing Atmosphere																		
Initial Deformation (I.D.)	2220	2230	2239	2185	2213	2209	2191	2199	2187	2200	2202	2242	2178	2213	2202	2230	2210	2220
Softening (H=W)	2226	2237	2247	2202	2220	2224	2201	2207	2196	2209	2213	2253	2190	2224	2212	2300	2240	2270
Hemispherical (H=1/2W)	2234	2243	2254	2216	2227	2237	2210	2216	2207	2219	2223	2264	2201	2234	2222	2340	2275	2308
Fluid	2242	2257	2267	2227	2238	2257	2221	2225	2217	2230	2232	2276	2211	2245	2232	2470	2320	2395
Mineral Analysis Of Ash (Ignited Basis)																		
Silica (SiO2)	40.00	39.14	39.92	36.31	37.29	38.94	39.06	38.87	38.33	38.18	38.90	39.87	32.67	46.78	38.58	41.60	41.46	41.53
Alumina (Al2O3)	16.70	16.37	16.75	16.56	16.17	17.14	17.70	18.55	17.83	17.37	16.99	17.98	16.62	16.60	17.46	17.26	17.28	17.27
Titania (TiO2)	1.32	1.32	1.44	1.46	1.34	1.34	1.41	1.38	1.39	1.33	1.27	1.22	1.51	1.29	1.35	1.14	1.20	1.17
Ferric Oxide (Fe2O3)	5.18	5.09	5.51	5.55	5.90	5.80	5.73	5.54	6.01	5.66	6.37	5.85	6.31	5.17	5.83	6.12	7.00	6.56
Lime (CaO)	20.07	20.76	19.45	22.25	21.64	19.89	20.93	20.94	21.30	21.58	19.00	18.68	24.36	16.85	20.46	14.48	15.45	14.97
Magnesia (MgO)	4.09	4.33	4.04	4.63	4.27	4.08	4.32	4.30	4.35	4.34	4.03	3.63	4.94	3.68	4.19	3.02	3.17	3.10
Potassium Oxide (K2O)	0.63	0.57	0.63	0.48	0.46	0.56	0.49	0.54	0.50	0.43	0.56	0.64	0.27	0.76	0.52	0.73	0.73	0.73
Sodium Oxide (Na2O)	1.39	1.52	1.36	1.41	1.40	1.36	1.60	1.56	1.56	1.66	1.41	1.29	1.49	1.02	1.42	0.95	0.96	0.96
Phosphorous Pentoxide (P2O5)	0.62	0.82	0.64	0.83	0.62	0.81	0.95	0.77	0.85	1.05	0.72	0.88	1.11	0.69	0.86	0.62	0.57	0.65
Sulfur Trioxide (SO3)	7.70	8.08	8.65	8.56	9.28	8.75	7.52	7.25	8.50	7.89	7.95	7.89	8.36	6.18	7.69	15.06	13.37	14.22
Strontium Oxide (SrO)	0.34	0.33	0.30	0.35	0.32	0.32	0.39	0.36	0.37	0.41	0.30	0.32	0.32	0.20	0.33	0.21	0.22	0.22
Barium Oxide (BaO)	0.61	0.61	0.53	0.62	0.58	0.64	0.56	0.54	0.55	0.59	0.46	0.47	0.64	0.44	0.53	0.43	0.45	0.44
Manganese Dioxide (MnO2)	0.02	0.02	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.03	0.03	0.02	0.03	0.01	0.01	0.01
Und.	1.13	1.04	0.77	0.97	0.89	0.47	-0.58	-0.63	0.43	1.58	2.02	1.25	1.37	0.42	0.73	-1.63	-1.97	-1.80
Total	100.00	100.00	100.00	100.00	100.00		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		100.00	100.00	
Base/Acid Ratio	0.54	0.57	0.53	0.63	0.61	0.56	0.57	0.56	0.61	0.61	0.55	0.51	0.74	0.42	0.57	0.42	0.46	0.44
T250	2281	2264	2286	2232	2239	2277.99	2265	2269	2243	2241	2275	2303	2163	2364	2267.88	2385	2350	2367.50
Water Soluble Alkalies (Dry)																		
Sodium Oxide	0.071	0.080	0.082	0.074	0.074	0.076												
Potassium Oxide	0.005	0.006	0.006	0.005	0.005	0.005												

DOCKET 070703 – EI
Progress Energy Florida
Exhibit No.: ____ (JS-5)
Page 7 of 7

overseen by the Vice President for Coal Procurement. Under his direction, coal prices were monitored on a continuing basis.

The record testimony reflects that when coal purchases were needed to supply PEF's plants, a competitive solicitation process was employed. RFPs were provided to all coal suppliers on the bidder list maintained by PFC. This list was comprised of over 100 suppliers, including PRB suppliers. In addition, PFC published notices of RFPs in coal industry publications to insure that anyone not on the bidders list had an opportunity to request to be on the list and to receive a copy of the RFP prior to the deadline. Coal procurement RFPs always included specifications for both bituminous and sub-bituminous coals, and solicited suppliers and brokers for domestic and foreign coals. PEF stated that it treated PRB suppliers the same as it did bituminous suppliers responding to the RFP. Any coal supplier would be added to the PFC bidders list upon request.

Once bids were received, they were evaluated and ranked based on evaluated cost or busbar cost using the Coal Quality Impact Model (CQIM). According to PEF, the model is a recognized industry standard and provides a "paper test burn" of the coal in a specific unit's boiler.

After the CQIM analysis identified the leading bids, in most instances, negotiations were then conducted with several bidders offering the lowest evaluated cost coals to obtain further price reductions. PEF used the same process for all of the RFPs issued over the period of 1996 through 2006.

Noting that witness Sansom testified that PEF could have encouraged PRB bids by sending letters directly to the coal producers, PEF contended it "sent seven such 'letters,' i.e. 'RFPs' to PRB coal producers" during 1996-2006 and received bids in response to four. OPC witness Sansom agreed that the PRB suppliers on PFC's bidders list comprised 70 to 80 percent of the PRB coal market production.

The record reflects that PFC examined the use of PRB coal regularly, including comparison of its fuel costs to those of Tampa Electric Company, which burned similar coal at its Gannon plant. Ongoing PFC comparisons showed that Tampa Electric Company was paying more for sub-bituminous coal than for bituminous coal. Sub-bituminous was not the lowest cost coal offered on an evaluated cost basis. In fact, it was generally not even competitive with other coal options.

PFC's interest in PRB coal was evidenced early by a 1998 internal memorandum written by PFC's Vice President for Coal Procurement, Dennis Edwards. After discussing barge versus rail transport plans, he stated, "I believe we should recognize that we will, in all likelihood, be using PRB coals at [CR] 4 & 5 by about 2000 (my guess)." Also, in 1999, PFC's internal analysis showed PRB would potentially be the most economical by 2003.

PEF made a procurement and operational decision to burn bituminous synfuel products in its CR4 and CR5 units beginning in 1999.[18] By 2001 and 2003, when spot purchasing peaked, the majority of these spot purchases were for synfuel. In 2001, 66 percent of PEF's coal was purchased on the spot market, followed by 60 percent in 2002, and 55 percent in 2003.

During the period of 1996-2002, PEF issued three coal bid solicitations, in 1996, 1998, and 2001. No PRB coal suppliers responded to the 1996 and 1998 bid solicitations. However, competitive PRB bids were submitted in response to the 2001 solicitation. PEF's evaluation of these bids identified PRB coal as the lowest evaluated cost alternative for a five-year contract. In fact, the most competitive bid received in response to the May 2001 RFP in terms of evaluated price was the PRB coal bid at two years offered by Arch Coal.[19] PEF ultimately negotiated a one-year contract for imported bituminous coal after negotiating with bidders who had submitted three-year contract offers. Regardless of the fact that PRB was not selected in the 2001 bid evaluations, we find that because these PRB bids were competitive in 2001, this knowledge should have triggered actions by PEF to put itself in a position to buy sub-bituminous coal if it should prevail in the very next coal solicitation. As noted above, PEF did not do so.

Furthermore, Witness Davis testified that in 2002, two large long-term contracts for bituminous coal expired. These were high-volume contracts. One of those expiring contracts, the Massey contract, constituted a purchase of over one million waterborne tons per year. Accordingly, PEF would have been in the position to augment its supply of coal for CR4 and CR5 with either a long-term PRB coal contract to replace expiring contracts, or spot purchases in those instances when PRB coal was the most cost-effective alternative.

We note that the relative mix of spot versus contract purchases made by PFC on behalf of PEF may have played a role in the emphasis, or lack thereof, given to PRB coal. During the period 1996-2005, PEF's mix of spot versus contract coal purchases varied widely. Witness Davis testified that PFC considered it prudent to have a "mixture of coal supply contracts by having an appropriate balance of long term, medium term, and 'spot' supply contracts." She also stated that the company would evaluate and forecast, using various industry services, "how much of our coal supply we wanted to be on medium-term contracts (such as 18 months to three years) and how much we wanted to purchase on a spot basis during a year."

The record reflects that while busbar analyses were conducted to evaluate bids, PEF did not always find it necessary to conduct an evaluated or busbar cost if PFC and PEF were familiar

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[18] Synfuel is coal that has been chemically altered by the addition of reagents, such as Bunker C oil, i.e., heavy fuel oil. Coal and coal fines are the feedstock for synfuel and can be combined with fuel oil under heat and pressure to produce coal briquettes. OPC has argued that PEF bought synfuel from its affiliates. PEF responded that synfuel was purchased from affiliates and non affiliates, alike, at a discount to bituminous coal.

[19] As set forth in Exhibit 41, the May 2001 RFP required a minimum of 425,000 tons annually. The Arch Coal PRB bid for the 2 year contract was for 2.4 million tons, or 1.2 million tons per year, at an evaluated price of $241.59/MMBtu. The next lowest evaluated bid price was $243.61/MMBtu, a foreign coal bid by Carbones Del Quasare, S.A., a three year contract offered at 1.6 million tons, or 530,000 tons per year. The lowest evaluated bid price for CAPP coal was $251.46/MMBtu, a three year contract offered at 1.425 million tons, or 480,000 tons per year. Three other PRB bids were received at evaluated prices lower than the lowest CAPP coal evaluated price, but all at significantly more tonnage than the minimum requirement.

with the pool of suppliers, and "with whose coal [PFC] had substantial experience, or on which [PFC] had previously done a busbar analysis." In contrast, witness Davis testified that sub-bituminous coal was a "type of coal in which an evaluated cost or busbar cost analysis could provide important information." Witness Davis also testified that "it was not practical to subject short term spot purchases to such modeling."

We find that since PFC did not conduct this type of analysis on spot market purchases, sub-bituminous coal may have suffered from being an unknown quantity during periods when the company emphasized spot market purchases. As witness Davis recognized, "Progress Fuel Corporation was a substantial purchaser in the spot market." We find this procurement focus created limitations that affected PEF's evaluation of PRB coals. This focus did not stem from a bias against PRB coals, but from the overall spot/contract mix and factors such as fuel price trend expectations.

We conclude that the overall purchasing methods and approach employed by PEF and PFC were generally reasonable. As required by Order No. 12645, PFC's coal procurement practices involved a competitive solicitation process. PEF provided substantial evidence of PFC's formal procedures regarding fuel procurement, including the application of such a competitive solicitation process. However, despite having an overall adequate process, we find that the company should have taken timely action to put PEF in a position to use PRB coal at an earlier point in time. Though the first-ever PRB coal bids were extremely competitive in 2001, PEF failed to take the actions that should reasonably have followed this development. PEF should have realized that PRB bids may prevail in its next RFP, and that taking actions such as preparing environmental permitting and acquiring a test-burn quantity of PRB coal should have begun immediately.

C. Coal Availability and Costs

1. Cost and Availability

We also analyzed whether PRB was available to CR4 and CR5 at a lower cost than that purchased by PEF for the years 1996 to 2005. OPC's witness Sansom presented the numbers of tons of PRB coal produced by year from 1992 to 2005 in Exhibit 7. Over the 1992 to 2005 period, production increased steadily from 200,000,000 to over 425,000,000 tons. During the 1996 to 2005 period, PRB coal producers were in an over capacity situation.

The situation was reflected in PRB coal prices in the 1990's, when Southern Company found it economical to convert ten of its coal units to PRB coal units. Witness Putnam testified that during his employment with Southern Company in the 1990's, he worked on converting several coal burning units in Alabama, Georgia, and Mississippi to PRB coal burning units, that some of the most competitive bidding competitions he experienced at Southern Company involved PRB opportunities, and that Southern Company and its utilities were "covered up with coal people . . . begging us to come visit the PRB region and to their mines so we would consider their coals."

D. Megawatt Capacity

PEF argued that its customers received a benefit by the use of higher btu bituminous coal at CR4 and CR5. PEF testified that it was able to generate 750 and 770 MW gross from the plant rather than the 665 MW gross the plant was designed for. OPC disagreed and testified that the plant was designed to generate the 750 and 770 MW using the design blend of 50/50 PRB and bituminous coals.

As stated, the CR4 and CR5 units are baseload, must-run units providing low cost power on a first-call basis, and any action that causes a reduction to the generation output of CR4 and CR5 would necessarily be replaced by generation that is more costly. We believe the continuing reliable operation of CR4 and CR5 is of paramount importance. Witness Toms testified that the basic issue in the operation of these units is reliable generation:

> [T]he biggest concern for me in terms of operation of Crystal River 4 and 5 is a potential derate. The company's energy control center expects me to run these units to get 732 and 735 net megawatt output.

Witness Toms explained that the units have historically operated at overpressure to produce 750 and 770 MW gross when called upon, providing about 732 to 735 MW to meet consumer demands. He attributed this high output to the larger boilers in these units, allowing for more coal to be burned. He testified that PEF's customers have gotten the benefit of increased output from the units. Witness Toms testified that he cannot achieve an output of 750 megawatts with only five pulverizers operating. He explained that changing particle size to increase feeder speed tends to slag the boiler. He later stated that, as to particle size, "smaller is better."

PEF witness Davis testified that PEF was aware of PRB coal in the period 1996-2002, and examined it regularly. She stated that, if PRB coals were to be used, PEF saw potential for derating and additional costs because of the difference between that fuel and the bituminous coal. Witness Davis testified that she worked closely with Mr. Dennis G. Edwards, who was VP of Coal Procurement and that he looked at PRB many times. Witness Davis described certain discussions she had with Mr. Roy Potter, who was manager of technical services and performed the quality analysis of coals to be used at Crystal River. According to witness Davis, Roy Potter was very highly regarded for his coal analysis, and that he responded to her inquiries with an explanation that burning the lower quality PRB coal would derate the boilers. Witness Davis provided documents that demonstrate that PEF continued to monitor PRB coal for potential future use in the period of 1996 through 2002.

In support of its position that there would be no derate with the design blend, OPC offered testimony of the design engineers, testimony regarding the operation of similar units, and exhibits consisting of portions of the original contract documents. We find that the testimony and exhibits are not conclusive evidence that CR4 and CR5 would continue to operate at 750 to 770 MW capacity if a 50/50 blend of coal were used.

The similar units that were discussed by OPC witnesses Sansom and Putman, along with the descriptive information provided by the witnesses, do not provide a sufficient basis to assume that they are identical to CR4 and CR5 with regard to design or performance. While the units may be the same or similar vintage, the record is limited as to evidence of capacity rating, efficiency, and performance of those units. Similar design of units is just one of a multitude of factors that might contribute to similar or dissimilar performance of those units at the present time. The record does not address how the units compare to each other in categories such as rank within the dispatch of their native generation fleet – except for the information that Plant Daniel was not called on as much as other plants. It would be a matter of speculation to draw an inference about how experience at any particular plant might be similar to, or dissimilar from, the expectations for PRB coal use at Crystal River.

The testimony provided by OPC witness Barsin was very detailed in regard to the efforts made within the original design to provide a sufficiency of fuel, as well as accommodations for slagging and fouling factors associated with PRB coal. However, there is not sufficient evidence of a "guarantee" of gross generation in a range of 750 MW to 770 MW, without regard to the fuel that might be involved. Notwithstanding the extensive effort described by witness Barsin to design a unit that would run well using the PRB blend, the record documents show the term "guarantee" only on the projected performance associated with steam flow of 4,737,900 lb/hr at 2500 psig and 1005 degrees Fahrenheit. The same documents confirm that the steam is to be supplied to a turbine rated at 665 MW. The contract documents included with the "Projected Performance" information make no mention of output beyond 700 MW. We find that the guarantee of 665 MW gross generating capacity burning the 50 percent PRB fuel blend is evident in the record. In addition, the record reflects that the steam equipment, as installed, is designed to operate without any time limit at pressures 5 percent greater than that required for the 665 MW nameplate capacity. While we believe that burning a 50 percent blend of PRB and bituminous coals would cause operational difficulties, we find that burning a lower percentage blend appears to be a viable option.

A test burn of lower percentage PRB was conducted by PEF at the Crystal River site in 2004. The blending was done off-site. The 2004 test burn was not completely successful. The PEF Strategic Engineering Group investigated the possibility of using PRB as fuel for CR4 and CR5 and issued a report which indicated that using PRB blended off-site at less than 30 percent and delivered by barge would offer substantial savings and fuel flexibility. The report concluded that a blend with bituminous coal and less than 30 percent PRB coal would act like bituminous coal. The report predicted savings for the years 2007-2010 from a 20 percent PRB blend, based on a high level of costs. Some expensive items, such as water cannons and soot blowers, would be necessary capital additions. Witness Hatt also indicated that PRB coal at blends under 25 percent could likely be used.

In 2005, PEF hired Sargent & Lundy to assess the use of PRB coal at CR4 and CR5. That study indicated that a blend under 30 percent was likely to prove cost effective. Blending off-site was recommended in that report as well. In 2006, PEF successfully completed a short-term test burn of a lower blend of PRB (20 percent) and bituminous coal.

We agree with PEF that the performance of CR4 and CR5 must not be compromised. To date, the evidence provided by PEF shows that CR4 and CR5 will be able to maintain availability and capacity while using a low percentage of PRB coal. The studies have all assumed that blending will be done off-site. We concur.

E. CR4 and CR5 Operational Matters

In addition to the potential for derate, the parties debated on the record whether the use of a blend of PRB coal would have created operational difficulties at CR4 and CR5. OPC argued that a change from the bituminous coal that has been burned at CR4 and CR5 to the "design blend" would involve minimal risks to the operation of CR4 and CR5. On the other hand, PEF argued that after CR4 and CR5 came on line, and before 1996, extensive trade knowledge developed regarding several operational issues associated with the use of coal from the Powder River Basin.

Witness Sansom testified that the boilers at CR4 and CR5 were sister units to the Belle River unit near Detroit and the Miller Plant in Alabama. He stated that all these boilers were designed together. He recounted some details regarding the way the boilers were designed to accommodate burning PRB. PEF witness Hatt, however, argued that OPC's witness Sansom "provides an ultra-simplistic explanation of the differences" associated with handling and using PRB coal, from an operational and safety perspective. PEF witness Hatt provided an assessment of the "sister units" concept used by the OPC witnesses. He explained that the similarities in design may be limited to specific sections of the equipment, such as the boiler. Witness Hatt stated that the coal-yard situations of the "sister units" are completely different from the Crystal River coal yard. Further, as to the matter of "similar design," witness Hatt used the illustration of two cars of the same make, model, motor, and drive train that could have significant performance and maintenance differences, as when one car is a "lemon." He testified that similar differences can exist between "sister units."

Moreover, the information provided by OPC's witnesses do not provide sufficient actual data for comparison with any operation other than Crystal River. Witness Putman's testimony regarding Plant Daniel reverting to high Btu fuel in order to return to full load generation implied that the Plant Daniel units have not operated at a high capacity factor when fueled with PRB coal. However, CR4 and CR5 are routinely high in the dispatch order and generate at a high capacity factor. We find that the issues of pulverizer capacity, burn rate, and capacity factors for those sister units are not sufficiently addressed in the record. These factors are critical factors by which to compare generating units. For example, we believe it would have been important to know how components of those comparable units work together in such functions as fuel storage, feeding and processing, or whether the fuel is drier or the particles are larger at the boiler entry point. The information provided indicates that some units do manage PRB successfully, according to their needs and requirements, but it is not possible to make a direct comparison between the alleged comparable units and CR4 and CR5 and how they would incorporate PRB coal in a cost effective manner.

OPC's argument on the operational affects of burning a PRB blend at CR4 and CR5 was also based on design documents that included PRB coal as a possible fuel, along with Illinois coal or high Btu bituminous coal. The facilities for CR4 and CR5 at Crystal River were designed and installed prior to 1985. OPC alleged that the capability of CR4 and CR5 to use a 50 percent blend of PRB was guaranteed in the design documents. According to OPC witness Barsin, in his experience the entire projected performance document was treated as a guarantee. He testified that the attorney for his company told him it was a guarantee. OPC argued that because the guarantee is part of the document, PEF should be able to operate CR4 and CR5 at overpressure and produce the same MW output as PEF produces with the bituminous coal now being burned. As addressed above, we are not persuaded by OPC's guarantee documents.

In contrast, PEF offered testimony of the actual experience at Crystal River. PEF witness Toms testified as to the day-to-day operations at CR4 and CR5, and the factors that are crucial to the units operating with the performance reliability that they have shown. For example, witness Toms testified that if the fuel rating falls lower than the range of 11,000 to 11,300 Btu/pound, CR4 and CR5 are not able to operate at overpressure. He explained that particle size of the fuel entering the boiler is crucial -- the smaller the better. He stated that in his experience five pulverizers are not sufficient to maintain the units at full capacity. Alternatively, the fuel grind might be set for a larger particle size in order to increase the flow through the pulverizer, but the pulverizers must grind to a size that does not slag the boiler.

We find the testimony of witness Toms to be persuasive. In comparing the experience recounted by witness Toms to the assertions made by witnesses Sansom and Barsin, there are different views as to the performance to be expected from CR4 and CR5. Although witness Barsin's explanation of his design, along with the calculations provided, might lead to a presumption that five pulverizers are adequate to supply either of the CR4 or CR5 units, the experience of witness Toms contradicts that presumption. Based on actual operating experience, witness Toms testified that with only five pulverizers available, the units cannot produce the expected 750 or 775 MW. The record indicates that particle size and silo capacity (or through-put) limit the production of the utility. Witness Barsin's testimony addressed design calculations. It does not sufficiently address particle size, or show why limits on silo capacity would not curtail the steam production.

OPC witnesses asserted that the installed equipment has been suitable for storing and blending PRB coal as fuel for generating electricity from the in-service date through 2006. We do not believe that the record supports the position that blending the "design basis coal" on-site at Crystal River. Issues of safety and cost are relevant to PEF's analysis. Current industry standards, as indicated in testimony and exhibits of PEF witness Hatt, are designed to manage the explosive characteristics associated with PRB coal. We believe that PEF would need to bring the Crystal River site up to current operating standards for handling PRB coal if that material were to be blended on site.

While we found that on-site blending and the burning of a 50 percent blend of PRB and bituminous coals would cause operational difficulties, we find that burning a lower percentage blend appears to be a viable option. A test burn of lower percentage PRB was conducted by PEF at the Crystal River site in 2004. The blending was done off-site. The PEF Strategic Engineering Group investigated the possibility of using PRB as fuel for CR4 and CR5 and issued a report which indicated that using PRB blended off-site at less than 30 percent and delivered by barge would offer substantial savings and fuel flexibility. The report concluded that a blend with bituminous coal and less than 30 percent PRB coal would act like bituminous coal. The report predicted savings for the years 2007-2010 from a 20 percent PRB blend, based on a high level of costs. Some expensive items, such as water cannons and soot blowers, would be necessary capital additions. Witness Hatt also indicated that PRB coal at blends under 25 percent could likely be used. Dust control would be necessary with the lower percentage blend, but capital investments are much lower when blending is offsite. In 2005, PEF hired Sargent & Lundy to assess the use of PRB coal at CR4 and CR5. That study indicated that a blend under 30 percent was likely to prove cost effective. Blending off-site was recommended in that report as well. The report recommends some equipment additions and modifications to go forward, and included a confidential assessment of cost for material and installation.

F. <u>CR3</u>

PEF argued that PRB coal carries significant risks of fires and explosions. PEF witnesses Franke and Miller testified that there are safety and regulatory concerns about burning PRB coal in units sited with a nuclear plant. The Crystal River site has a nuclear unit – CR3 – and four coal units – CR1, CR2, CR4, and CR5. CR3 has a capacity of approximately 838 MW and came online in early 1977. The nuclear unit is subject to regulation by the Nuclear Regulatory Commission (NRC). Both witnesses Franke and Miller testified that there are no nuclear units collocated with coal plants that burn PRB.

CR1 and CR2 were the first units built at the Crystal River site. CR3 followed and began operation in 1977. CR4 and CR5 were built after CR3. PEF updated its Final Safety Analysis Report (FSAR), an important NRC licensing document, when CR4 and CR5 were built. According to witness Franke, PEF did not tell the NRC that the units were designed to burn a 50/50 blend of bituminous and sub-bituminous coal. The FSAR reflected PEF's expectation to use bituminous coal at CR4 and CR5. The updated FSAR reflected the site's layout, including coal piles, handling equipment and conveyors and the proximity of these features to the reactor building. We note that both the industry's understanding of the risks posed by PRB coals and nuclear safety standards have changed since CR4 and CR5 became operational.

As stated, in 2004, a test burn for a blend of PRB coal was conducted. CR3 staff were contacted when the 2004 test burn was planned. The CR3 staff expressed concern and required that the blend with PRB coal be blended off-site. The blend burned during the 2004 test burn had 15 percent to 22 percent PRB coal.

In its brief, White Springs stated the following:

> In sum, at most Mr. Franke and Mr. Miller's testimonies do little more than describe the NRC rule on risk assessment and possible license amendments. Since none of the assessments Mr. Franke claims must be performed have even been started, there is only conjecture regarding what action (e.g., filing a report, mentioning PRB coal use in the next update to the FSAR, request for a license amendment, etc.) might be required by the NRC.

PEF, prudent steps were not taken. We find that PEF management's failures to act despite its affiliate managements' knowledge that PRB coal was a cost-effective alternative was imprudent. We find that while PEF did not pay excessive fuel costs for the years 1996 through 2002 it did pay excessive fuel costs from 2003 through 2005.

PFC's evaluation of the market response to the May 2001 RFP proved that PEF could no longer afford to be unprepared to purchase PRB coal on either a spot or contract basis. With the May 2001 bid responses, PEF's management had received incontrovertible evidence, even assuming PEF waterborne proxy transportation rates, that PRB represented a very competitive coal purchase option for PEF's CR4 and CR5 generating units for both current and future coal purchases. To prepare for such purchases, PEF should have immediately sought a permit revision and conducted test-burns of PRB coal at CR4 and CR5. According to PEF's witness Kennedy it would have taken PEF approximately 14 months to amend its Title V permit. If PEF management had pursued PRB coal aggressively beginning in May 2001, PEF would have positioned itself to be permitted and ready to burn PRB coal by no later than January 2003. However, as PEF's testimony reveals, PEF did not know that it was not allowed to burn PRB coal per its Title V permit at the time of its April 2004 test burn. The period of May 2001 through April 2004 represents a three-year period during which PEF's lack of awareness of the permit status of its own power plants cannot be viewed as simple managerial oversight.

Order No. 12645 includes a recovery criterion that all expenses associated with fuel procurement be reasonably competitive in cost or value relative to what other buyers are paying under similar terms and conditions. CR4 and CR5 were designed to burn PRB coal, PRB coal was evaluated by PEF as a competitive alternative in May 2001, coal transport options were available to PEF for PRB coal deliveries, and many other Southeastern utilities were purchasing PRB coal for their power plants. Given these circumstances, we find that PEF was imprudent to not immediately seek permit modification to allow PRB to be burned at CR4 and CR5 after its May 2001 bid evaluation.

On the matter of coal procurement practices, we find that if PEF had taken the prudent step of obtaining a revision to its Title V permit in mid-2001, it would have been in the position to seize upon market opportunities for PRB coal by January 2003. Two high-volume long-term coal contracts for CR4 and CR5 expired in 2002, and one of those expiring contracts was the Massey contract, constituting a purchase of over one million waterborne tons per year. PEF would have been in the position to augment its supply of coal for CR4 and CR5 with either a long-term PRB coal contract to replace expiring contracts, or spot purchases in those instances when PRB coal was the most cost-effective alternative. We find that it was imprudent for PEF to not purchase PRB coal when it was cost-effective to do so in 2003-2005.

Regarding CR4 and CR5 operational matters related to burning PRB coal, the capital and operational cost impacts of burning PRB coal at these units would be quite limited if the quantities were restricted to blends less than 30 percent PRB coal blended off-site. Thus, we find that the evidence in the record indicates that PRB coal blends less than 30 percent for CR4 and CR5 could have been purchased for the January 2003 through December 2005 period without incurring large incremental capital or operating costs. We find that PEF was imprudent

PEF witness Heller testified that rather than incurring excessive costs for coal procurement, the company achieved a total value of $733,323,926 in savings from 1996 to 2005 by using exclusively bituminous coals at CR4 and CR5 rather than a 50/50 blend of CAPP coal and PRB coal. According to PEF, this total savings amount was a combination of three separate calculations: (1) witness Heller's estimate of fuel savings ($51,376,000) assuming all fuel and operational costs but excluding replacement power costs which would have resulted from derates due to using a 50/50 blend of CAPP and PRB coals at CR4 and CR5 during the 1996 to 2005 period, (2) witness Crisp's estimate of the derate costs ($696,963,130) due to using a 50/50 blend, and (3) witness Dean's offsetting SO2 allowance costs (-$15,015,204).

Witness Heller analyzed the potential for savings based on a comparison of his evaluated price of PRB coal to the actual delivered price of CAPP coal for all years. For annual PRB delivered coal prices, witness Heller utilized market information to obtain an FOB mine price for PRB coal, the cost of specific rail movements to docks on the Mississippi River, PEF-specific barge transfer costs, and the Commission-approved waterborne coal transportation proxies for the remainder of the transport costs (river, terminaling, and cross-Gulf transportation). Witness Heller adjusted PRB delivered prices to derive evaluated prices in order to account for additional operation and maintenance costs due to the impact of variations in the quality of the coal on boiler operations. Finally, witness Heller included the mid-point of the capital and operating costs identified by witness Hatt associated with the capital and operating costs associated with converting CR4 and CR5 to burn a 50/50 blend of CAPP/foreign coal and PRB coal.

According to PEF witnesses, the excessive SO2 allowance costs for 2003 through 2005 amount to $2,779,308. These costs were calculated based on the same procedure used by witness Sansom except PEF's calculation includes no ash adjustment but does include an adjustment to OPC's MMBtu data. Witness Dean provided an analysis of SO2 costs for all relevant years.

We found, as set forth above, that PEF was prudent in its coal purchases from 1996 through 2001. Thus, consistent with our analysis above, we find the appropriate refund amount for those years is zero.

Although we find PEF's coal purchases to be prudent from 1996 to 2001, beginning in 2001, PEF made imprudent management decisions. As more specifically discussed above, had PEF followed a prudent course of conduct in 2001 and 2002, ratepayers would have benefited from lower coal and emissions costs from 2003 to 2005. We find that PEF would have needed time to prepare itself to burn PRB. The record reflects that it would have taken 14 months to obtain a Title V permit amendment. Had PEF taken the appropriate actions in 2001, it would have been ready to burn PRB by 2003. We find that PEF's excessive coal costs in 2003 through 2005, inclusive of SO2 emissions costs, as shown on Attachment A, amounted to $12,425,492. These costs were calculated based on:

- Waterborne delivery of 2.4 million tons of coal per year from IMT to Crystal River, based on an 80/20 blend of CAPP/foreign coal to PRB coal for CR4 and CR5, including 480,000 PRB coal tons per year for 2003 and 2004, and 444,000

PRB coal tons in 2005 (thereby taking into account waterborne coal delivery constraints at Crystal River and rail transportation constraints in 2005);

- Assurance that the 480,000 tons per year of PRB coal in 2003 and 2004 does not exceed the waterborne coal supply requirements not yet contracted prior to 2003;

- A cost-effectiveness test of PRB coal for 2003, 2004, and 2005 for PEF, wherein the delivered price of CAPP/Foreign coal cost was shown to be higher than the evaluated price of PRB coal on a $/MMBtu basis;

- The PRB coal evaluated price was inclusive of those specific plant and operational incremental costs necessary for expected use of an 80/20 blend of CAPP/Foreign to PRB Coals at CR4 and CR5;

- The blending costs associated with PRB coals in Davant was included in the delivered PRB coal costs and was consistent with the PRB blending costs recognized by both OPC and PEF; and

- SO2 emissions costs based on the PRB tonnages cited above (480,000 tons per year for 2003-2004 and 444,000 tons in 2005) and PEF Witness Dean's estimates of PRB's SO2 content, heat rate, and SO2 emission allowances prices.

We accepted the testimony of witness Heller that Crystal River transportation constraints would have limited the waterborne delivery of coal to CR4 and CR5 to 2.4 million tons per year. Witness Heller said that PEF has attempted to exceed this amount but incurred operational problems when it did. No intervenor challenged this delivery constraint. An 80/20 blend of CAPP/foreign to PRB coal with the constraint of 2.4 million tons per year, blended off-site, is consistent with our analysis above, and yields a maximum tonnage of PRB of 480,000 tons (20 percent times 2.4 million tons per year).

We examined whether PEF could reasonably have contracted for 480,000 tons of waterborne coal during 2003 through 2005 without exceeding their supply requirements not already contracted. We note that PEF engaged in spot purchases of waterborne bituminous coal during 2003 through 2005 in amounts in excess of the PRB coal volumes necessary to achieve an 80/20 blend of CAPP/foreign coal to PRB coal. PEF also engaged in new long-term contracts for waterborne bituminous coal purchases during the 2003 through 2005 period. We find that PEF could reasonably have purchased 480,000 tons of coal each year without exceeding CR4 and CR5 waterborne coal supply requirements for those years not already contracted.

The record indicated that the capital and ongoing O&M costs for a 20 percent PRB coal blend at CR4 and CR5 would have been minimal compared to the costs required for a 50 percent PRB blend at CR4 and CR5. Our cost-effectiveness test for the 20 percent PRB coal blend, blended off-site, recognizes ten percent of the total capital costs requirements for 50/50 blend, blended on-site, per witness Heller. The Sargent and Lundy report gave a range of costs that would be incurred if PEF blended less than 30 percent PRB coal. We selected ten percent as a reasonable midpoint of the range of costs given the "coal blends less than 30 percent PRB" cost handling and safety issues, unit operation and performance, and environmental emissions. The test burn can either be on a short-term or long-term basis. Typically, when first evaluating a coal product of different quality or type, a short-term test of two to three days will be conducted. The purpose of a short-term test burn is to see if any immediate handling, performance, environmental, or safety issues are present. Short-term test burns are also sometimes required for environmental permitting.

A long-term test burn can last anywhere between three and six months. The purpose of a long-term test burn is to see how the unit will perform over a sustained period of operation and under variations in environmental conditions that the units typically experience over a longer period of time. With long-term test burns, PEF can get a good idea of whether a new type of coal will be suitable for PEF to use in the plants on an extended basis.

Q. **Why is it important for PEF to conduct test burns prior to introducing a new type or quality of coal into the units?**

A. Certain equipment in the plants, such as the boiler and electrostatic precipitator for example, are especially sensitive to changes in coal quality and types. It is important, therefore, for PEF to know how the plants will react to new types and qualities of coal on a short- and long-term basis. New coal products may cause de-rates (or loss of energy production or load) or forced outages in the units. Either way, the units are not producing the energy that is expected from them. Test burns allow PEF to identify any such operational and production issues prior to making a full-scale commitment to switch to or use a new coal product.

From Wayne Toms' testimony;
Docket 060658

The Company further needs to know if changes in the quality or type of coal will affect the cost of handling the coal or operating the units. Coals with higher moisture content than historically specified and used at the units, for example, create handling and operational issues. Additional effort will need to be made on the coal piles in handling the coal to assist in drying it out, and more heat will need to be used at the pulverizers to dry the coal out before it is blown into the boilers to be burned. This will increase the maintenance costs and increase the wear and tear on certain equipment, like the pulverizers, in the units. These impacts are important to know because they may lead to additional forced outage and maintenance time and cost.

Test burns can also be important from a safety perspective because certain types of coal require different handling and use procedures. This is particularly true for sub-bituminous coals from the PRB, which are dustier, more volatile, and thus more difficult to handle from a safety standpoint than bituminous coals. Test burns allow PEF to become accustomed to such changes in use and handling procedures, and to adjust them as necessary from actual experience, prior to full-scale use.

Q. What are your goals with respect to test burns for new coal products at CR4 and CR5?

A. I want to know how the new coal product is going to affect my responsibilities to safely and efficiently operate CR4 and CR5, make CR4 and CR5 commercially available for ECC, and to achieve full capacity production at between 750MW and 770MW when called upon to do so to meet customer load. If there is an impact on our ability to safely and efficiently handle the new coal product, or our ability to

From Wayne Toms' testimony;
Docket 060658

Q. How did you perform the analysis?

A. I reviewed the delivered prices of coal to CR4 and CR5 during the 2006-2007 period and identified the mix of coals burned at the plant. I reviewed information as to whether the coals were delivered by rail or water. I also considered the price of the coals actually delivered. These coals were either from Central Appalachia (CAPP) or were imports from South America. Central Appalachia refers to a coal supply region including eastern Kentucky, West Virginia, Virginia and Tennessee which is the primary eastern US low sulfur bituminous coal producing region. I ranked these coal deliveries over time in terms of their delivered costs. I also examined the PRB coal bids received by PEF during 2006 and 2007 to determine how the evaluated cost of PRB coals would have compared with the evaluated cost of the most expensive coals that were actually delivered.

Q. Did you perform the analysis on a delivered price or "evaluated" price basis?

A. I performed the comparisons on an "as-burned" or "evaluated" price basis. This is because in comparing coals of very different characteristics, it is important to understand how they affect boiler operations and unit output (October 10th Order pages 29-30, 37). A relatively low Btu, high moisture coal like a PRB coal generally has a negative impact on boiler performance and plant operating costs, while its lower sulfur content has a positive impact on emissions. PEF analyzed these differences in coal quality characteristics and calculated adjustments to evaluate these differences and express them on a cents per million Btu basis. I understand that PEF uses the Vista model, which was developed by Black and

From James N. Heller's testimony;
Docket 070703

PRB coal that OPC suggests PEF should have been burning all these years -- has a significantly lower BTU content than the bituminous coal that PEF has been using. A BTU, or British Thermal Unit, is the amount of heat that a given fuel source generates when it is burned. Said simply, the higher the BTU content, the better and more efficient the fuel source. The sub-bituminous PRB coal that OPC contends PEF should have been using typically has a BTU value in the 8,500 BTU range. The bituminous coal that PEF has historically used generally has a BTU value in the 12,000 to 13,000 BTU range. This has allowed PEF to burn about 50% less coal to get the same amount of heating energy when compared to a straight PRB coal.

Q. Are there any other differences between bituminous and sub-bituminous coal?

A. Yes, several, but here, I will focus on the other major differences that are most relevant to this case. Because of its chemical composition and physical nature, PRB sub-bituminous coal is much more volatile and dangerous compared to the bituminous coal that PEF has historically used. Unlike bituminous coal, PRB coal has a tendency to "self ignite" or spontaneously combust once it is removed from the ground. In fact, PRB coal is classified as explosive by the U.S. Bureau of Mines. Therefore, as reflected in Exhibit No. __ (RH-2), the Material Data Sheet regarding PRB sub-bituminous coal, great care must be taken when dealing with PRB coal.

Similarly, PRB coal, as shown in Exhibit No. __(RH-3), is a much less physically stable coal and will break up and dust much more than bituminous coal. PRB coal dust is not only problematic from an operational level, it is also flammable and can cause explosions, equipment fires, and airborne "dust fireballs" if not properly cared for. Indeed, as shown in the attached Exhibit No. __ (RH-4), the

From rod Hatt's testimony;
Docket 060658

A. The Company uses the Coal Quality Impact Model (CQIM), as updated, which was developed for the Electric Power Research Institute (EPRI) by Black & Veatch and introduced to determine the impact of variations in coal quality upon generation costs. This model or an equivalent is widely used for performing such analyses. It was developed for "evaluating Clean Air Act compliance strategies, evaluating bids on coal contracts, conducting test burn planning and analysis" among other functions. See Exhibit No. __ (JNH-1). In my experience, this is the model relied upon by companies in the industry who do the most sophisticated analysis of coal quality impacts on boiler operations.

Because the Company generally burned central Appalachian coals that were similar in quality characteristics, however, they could simply evaluate these CAPP coal bids on a delivered price basis and choose the lowest cost bids. Since the Company was purchasing coal and transportation from affiliates, the approach of ranking coals on a least cost delivered basis made the evaluations more transparent and less subject to criticism that somehow the process was being manipulated to favor affiliate coals.

The testimony of Mr. Hatt describes in more detail the relationship between coal quality and unit performance.

Q. **Did PEF solicit PRB coals?**

A. Yes. It is clear that PEF had solicited bids for PRB coals since at least 1998. The bid solicitations explicitly contain provisions for sub-bituminous coals and the bidder lists and bid response lists include producers of PRB coals.

From James N. Heller's testimony;
Docket 060658

Q. Now, starting with mining, or the "seam," how does mining PRB coal compare to bituminous coal?

A. PRB is a younger coal, geologically speaking. This contributes to the PRB coal having properties associated with increased reactivity, which causes concern for increased fires and flammable coal dust. The more the coal is exposed to air, the more likely the coal dust and the coal itself will ignite. So the moment PRB coal is removed from the coal seam, there are potential problems with flammable dust and coal fires. Anyone mining PRB coal has to account for these factors and take measures to deal with them when mining the coal and placing it in silos for shipment. For example, as seen in the attached Exhibit No. __ (RH-6), there have been several reports dealing with mine fires at PRB coal mines.

Q. What issues are associated with loading PRB coal into silos at the mines?

A. The first issue is the potential for fires in the coal silo. Those mining PRB coal, and ultimately those purchasing it, have to be cognizant of and factor in PRB coals' increased volatility.

Second, because it is a younger, less stable coal, PRB tends to lose its BTU content faster than bituminous coals once the coal is removed from the earth. Because of this fact, PRB mines are usually adamant that they will measure coal BTU specifications at the mine and not where the coal is ultimately delivered. This means the potential purchaser likely will not get the amount of BTUs that it is actually paying for.

From rod Hatt's testimony;
Docket 060658

A. It is more difficult to remove mercury from PRB coal. Even though there is less mercury in PRB coal than in bituminous coal, the chemical composition of PRB coal reduces the effectiveness of the scrubber in removing the mercury. Therefore, the scrubber can remove a higher percentage of the mercury from bituminous coal than it can from the PRB coal. Other devices, such as sorbent injection and baghouses, may need to be installed to sufficiently remove the mercury from PRB coal.

Q. Does the Company have any plans to install scrubbers on CR4 and CR5?

A. Yes, currently PEF will install scrubbers on CR5 by the end of 2009 and on CR4 by spring of 2010. The Company is installing these scrubbers to comply with the CAIR and CAMR requirements. It began planning the installation of these scrubbers in 2004, prior to the enactment of CAIR and CAMR, because the Company realized that the rules were being proposed and would likely become requirements.

Q. What concerns, if any, do you have with burning a PRB/bituminous coal blend at CR4 and CR5, given the planned installation of these scrubbers?

A. As explained above, with a scrubber a plant can burn cheaper, higher-sulfur coal. If one of the alleged benefits of PRB coal is the reduced SO_2 emissions, the need for lower-sulfur coal is greatly reduced with a scrubber. And the cost of PRB coal must be compared to high-sulfur coal, not to low-sulfur Central Appalachian "compliance" coal. This makes the price of PRB coal appear less economical. In

From Mike Kennedy's testimony;
Docket 060658

JOURNAL INTERACTIVE

We Energies coal dust silo explosion injures 6 workers

By Tom Kertscher of the Journal Sentinel

Posted: Feb. 3, 2009

Oak Creek - An explosion Tuesday morning inside a We Energies coal dust silo rained flames down on a group of contract employees who were making preparations for repair work to begin.

Four employees were inside the 65-foot-tall structure and two outside when the explosion occurred, said a We Energies spokesman. A doctor said a 43-year-old man pulled his son, 22, and at least one other co-worker to safety.

The 22-year-old was the most severely injured, suffering burns to more than half his body, according to Tom Schneider, medical director of the Columbia St. Mary's Regional Burn Center in Milwaukee.

The cause of the blast, reported at 10:53 a.m., has not been determined. Federal and local authorities will be investigating, officials said.

The six workers are employees of the Milwaukee branch of ThyssenKrupp Safway, a Waukesha-based company that provides scaffolding services, said Michelle Dalton, a company spokeswoman. She would not identify the workers.

ThyssenKrupp was hired as a subcontractor by United States Fire Protection, a New Berlin firm that provides fire protection services, according to We Energies spokesman Brian Manthey.

A spokesman at United States Fire Protection could not be reached. But the firm was hired by We Energies to perform repairs at the silo, which was constructed in November 2007, Manthey said.

After the blast, firetrucks and rescue squads from as far away as Wauwatosa and the North Shore responded.

Two of the victims were transported to hospitals by helicopter, said Oak Creek Assistant Fire Chief Tom Rosandich.

The 43-year-old and other workers described a bit of their ordeal while the emergency room doctors and burn unit surgeons tended to them in the early afternoon.

They described the fire rolling down at them from the top of the silo, and a fast scramble to escape through a door. One worker jumped from a scaffold to escape, according to Schneider.

The 43-year-old and a 23-year-old co-worker were treated at Columbia St. Mary's and released Tuesday afternoon. They had minor burns to their hands and faces.

Three other workers, ages 27, 29 and 34, suffered second- and third-degree burns, also predominantly to their hands and faces. All were in fair condition, Schneider said.

He said one of them will need skin grafts on his hands, likely requiring a hospital stay of 10 to 15 days, but the other two should be discharged within a day or two.

The 22-year-old worker was taken to Froedtert Hospital in Wauwatosa because of challenges in establishing a clear airway, Schneider said.

He was later transported to Columbia St. Mary's, where he was in critical condition Tuesday evening, said hospital spokeswoman Kathy Schmitz. No further information on his condition would be released, Schmitz said.

The silo, one of nine at the plant, is used to collect coal dust that accumulates from coal that is brought by train to the plant, said We Energies spokesman Barry McNulty.

He said the dust is compacted and, like coal itself, is burned for fuel.

Much like gas vapors, coal dust becomes explosive when it reaches certain concentrations in an enclosed area.

An explosive concentration would obscure objects viewed from about 6 feet away, according to Guy Colonna, a combustible dust expert with the National Fire Protection Association.

The lightest dust particles become the most hazardous, rising unnoticed to the upper reaches of a work space, he said.

Colonna said heat or sparks from operating machinery, static electricity or some type of cutting or welding are common ignition sources in industrial settings.

The coal-handling facility that includes the silo that exploded is part of a $2.3 billion construction project that is expanding the Oak Creek power plant.

The facility was built by Bechtel Power Corp. and began operation in October 2007. The facility cost $175 million, according to We Energies.

We Energies and Bechtel Power Corp. are locked in a $485 million dispute over whether Bechtel should be compensated for construction delays the contractor has experienced at the power plant site.

Thomas Content of the Journal Sentinel staff contributed to this report.

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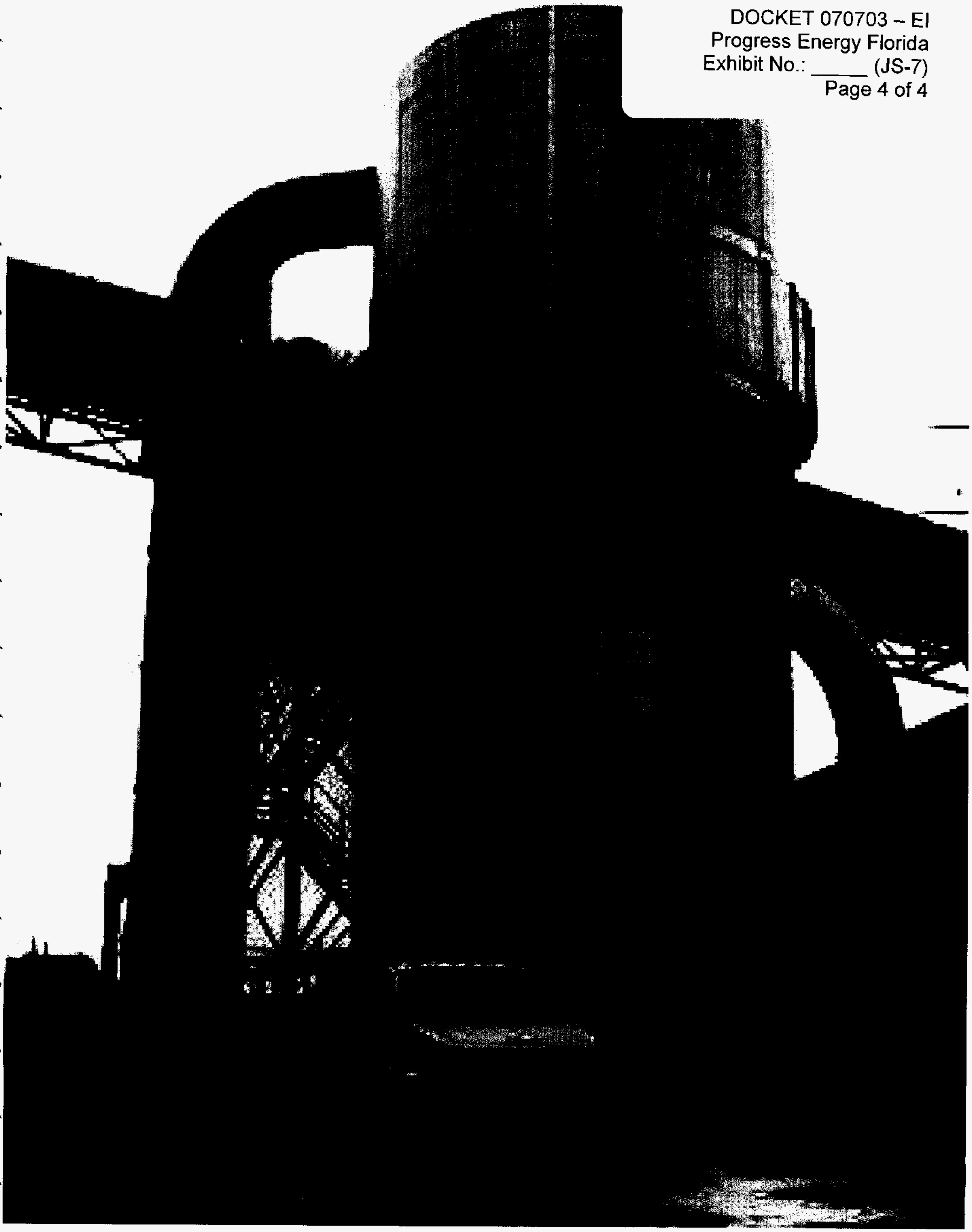

Estimate of Costs for Capital Additions

	Capital Equipment	Purpose	Other Considerations	Cost (both units)
Slagging & Fouling	Water Cannons	Sprays large amounts of water onto waterwalls to remove slagging buildup	• Would need 4 per unit • May cause quench cracking of boiler tubes leading to tube leaks and de-rates • May need to review water permit for increased water usage • Would replace current wall blowers in lower furnace area • Requires outage for installation	$ 3 – 4 million
	Upgrade Soot Blowers	Steam Soot Blowers installed in upper area of furnace – beginning of convection pass to address slagging & fouling issues	• Newer configuration designed to withstand increased usage and maintenance • 36 SB per unit • Potential for tube erosion	~ $1.5 million
	Retractable Soot Blowers	Long-reach steam soot blower to address convection pass fouling	• Would need 6 per unit (3 sets) • Potential for tube erosion	$600K – $1 million
	Convection Pass Modifications	Replacement of superheater/reheater tube banks	• Increase spacing between tubes to handle high to severe fouling • Requires outage for installation	$5 - 10 million
	Intelligent Soot Blowing System	Automates soot blowing sequences to address slagging & fouling as it is detected	• May reduce rate of tube erosion from increased soot blowing • Requires outage for installation	$600K - $1 million
	Furnace Cameras	Used for visual verification of slagging issues	• Requires outage for installation of ports	~ $250K
	Furnace Exit Gas Temperature (FEGT) probes	Used to determine exit gas temperature	• Compare to ash fusion temperature of fuels to help predict relative amount of slagging	~ $100K
Fuel Handling	Online Coal Analyzer	Assists with coal characteristic identification	• Can provide advanced indication of potential boiler issues • Some systems are radiation-based – safety concerns	~ $500 K
Unit Performance	Additional Pulverizer	To increase coal feed throughput	• One slot available per unit • Would also require coal feeder and silo installation for complete pulverizer system • Requires outage for installation	~ $4 – 10 million
Opacity & PM Emissions	ESP SO_3 Conditioning System	Used to decrease the flyash resistivity for improved ESP collection efficiency	• Will be difficult to permit due to increase in sulfur acid emissions • May require outage for installation	~ $2.4 million
	ESP Upgraded Internals	Includes: Flow modeling, New rigid electrodes plates, spacing changes, modified rapper system, increased height for more collection area, etc.	• Requires outage for installation • This cost estimate represents full replacements to only 2 of the 5 ESP sections, and limited replacements in the other 3 sections	~ $45 million
	Baghouse Conversion	Used to collect particulate emissions that may not be captured by an ESP	• May be needed to address high resistivity ash and mercury collection from sub-bituminous coals • There may be spacing constraints for locating base • Significant additional annual costs for maintenance costs & auxiliary power • Requires outage for installation	$80 -100 million

Coal Quality Comparison
Peabody PRB versus Spring Creek Sub-Bituminous
Typical Qualities

	Central Appalachian		Peabody PRB		Spring Creek Coal		% Change (Lbs/Mbtu)
	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	
Moisture	8	6.5	28.04	32.7	25.04	27.17	-17%
Ash	12	9.76	6.58	7.67	4.12	4.41	-43%
Volatile	35	28.4	31.04	36.2	31.3	33.4	-8%
Sulfur	0.72	1.17	0.4	0.93	0.34	0.73	-22%
Btu/lb	12,300		8,574		9,350		9%
Carbon	67.16	54.6	49.75	58	54.14	57.9	0%
Hydrogen	4.3	3.5	3.57	4.2	3.8	4.1	-2%
Nitrogen	1.1	0.9	0.65	0.8	0.72	0.8	0%
Oxygen	6.1	5	11.01	12.8	11.5	12.3	-4%
Iron	8	0.78	6.12	0.47	4.26	0.21	-55%
Calcuim	2	0.20	14.48	1.11	15.36	0.68	-39%
Sodium	0.5	0.05	0.95	0.07	**8.24**	**0.36**	**414% more**
Base/Acid	0.17		0.42		**0.64**		**51% more**
% Silica	83.1		63.78		57.73		-9%
Self-Heating Temp (°F)	192.9		83.3		89.8		8%

	80% CAAP & 20% PRB		80% CAAP & 20% Spring Creek Blend		% Change (Lbs/Mbtu)
	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	
Moisture	12.01	10.39	11.48	9.8	-6%
Ash	10.91	9.44	10.42	8.9	-6%
Volatile	34.2	29.58	34.22	29.2	-1%
Sulfur	0.65	1.13	0.64	1.09	-4%
Btu/lb	11,555		11,710		1%
Carbon	63.68	55.1	64.56	55.1	0%
Hydrogen	4.39	3.8	4.44	3.8	0%
Nitrogen	1.01	0.9	1.03	0.9	0%
Oxygen	7.08	6.10	7.18	6.10	0%
Iron	7.63	0.72	7.54	0.67	-7%
Calcuim	3.82	0.36	3.21	0.29	-21%
Sodium	0.56	0.05	**1.22**	**0.11**	**106% more**
Base/Acid	0.20		0.20		0%
% Silica	80.18		80.95		1%

Coal Quality Comparison
Peabody PRB versus SSM-Kideco Sub-Bituminous
Typical Qualities

	Central Appalachian		Peabody PRB		PT Kideco		% Change (Lbs/Mbtu)
	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	
Moisture	8	6.5	28.04	32.7	30	36.59	12%
Ash	12	9.8	6.58	7.67	4	4.9	-36%
Volatile	35	28.4	31.04	36.2	36	43.9	21%
Sulfur	0.72	1.17	0.4	0.93	0.08	**0.20**	**-78% less**
Btu/lb	12,300		8,574		8,200		-4%
Carbon	67.16	54.6	49.75	58	45.03	54.9	-5%
Hydrogen	4.3	3.5	3.57	4.2	3.3	4	-5%
Nitrogen	1.1	0.9	0.65	0.8	0.56	0.7	-13%
Oxygen	6.1	5	11.01	12.8	17.02	20.8	63%
Iron	8	0.78	6.12	0.47	21.14	1.03	**119% more**
Calcuim	2	0.20	14.48	1.11	16.35	0.80	-28%
Sodium	0.5	0.05	0.95	0.07	0.11	0.01	**-93% less**
Base/Acid	0.17		0.42		**1.02**		**142% more**
% Silica	83.1		63.8		41.6		-35%
Self-Heating Temp (°F)	192.9		83.3		36.5		**-56% less**

	80% CAAP & 20% PRB		80% CAAP & 20% PT Kideco Blend		% Change (Lbs/Mbtu)
	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	
Moisture	12.01	10.39	12.4	10.8	4%
Ash	10.91	9.44	10.4	9.1	-4%
Volatile	34.2	29.58	35	30.64	4%
Sulfur	0.65	1.13	0.59	1.03	-9%
Btu/lb	11,555		11,480		-1%
Carbon	63.68	55.1	62.57	54.5	-1%
Hydrogen	4.39	3.8	4.34	3.8	0%
Nitrogen	1.01	0.9	1	0.9	0%
Oxygen	7.08	6.10	8.28	7.2	18%
Iron	7.63	0.72	9.07	0.82	14%
Calcuim	3.82	0.361	3.33	0.30	-17%
Sodium	0.56	0.053	0.45	0.041	-23%
Base/Acid	0.20		0.22		10%
% Silica	80.18		78.3		-2%

Coal Quality Comparison
Peabody PRB versus PT Adaro Sub-Bituminous
Typical Qualities

	Central Appalachian		Peabody PRB		PT Adaro		% Change (Lbs/Mbtu)
	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	
Moisture	8	6.15	28.04	32.7	27.1	29.54	-10%
Ash	12	9.76	6.58	7.67	1.2	1.31	-83%
Volatile	35	28.4	31.04	36.2	36.9	40.22	11%
Sulfur	0.72	1.17	0.4	0.93	0.09	0.20	-78% less
Btu/lb	12,300		8,574		9,175		7%
Carbon	67.16	54.6	49.75	58	53	57.8	0%
Hydrogen	4.3	3.5	3.57	4.2	3.5	3.8	-10%
Nitrogen	1.1	0.9	0.65	0.8	0.6	0.7	-13%
Oxygen	6.1	5	11.01	12.8	14.5	15.8	23%
Iron	8	0.78	6.12	0.47	21.74	0.28	-40%
Calcuim	2	0.195	14.48	1.111	11.41	0.15	-86%
Sodium	0.5	0.049	0.95	0.073	0.16	0.002	-97%
Base/Acid	0.17		0.422		0.844		100%
% Silica	83.1		63.78		43.9		-31%
Self-Heating Temp (°F)	192.9		83.3		47.4		-43% less

	80% CAAP & 20% PRB		80% CAAP & 20% PT Adaro Blend		% Change (Lbs/Mbtu)
	Percent %	Lbs/Mbtu	Percent %	Lbs/Mbtu	
Moisture	12.01	10.39	11.82	10.12	-3%
Ash	10.91	9.44	9.84	8.43	-11%
Volatile	34.2	29.58	35.35	30.28	2%
Sulfur	0.65	1.13	0.59	1.01	-11% less
Btu/lb	11,555		11,675		1%
Carbon	63.68	55.1	64.33	55.1	0%
Hydrogen	4.39	3.8	4.38	3.8	0%
Nitrogen	1.01	0.9	1	0.9	0%
Oxygen	7.08	6.10	7.78	6.7	10%
Iron	7.63	0.72	8	0.68	-6%
Calcuim	3.82	0.361	2.2	0.18	-50%
Sodium	0.56	0.053	0.47	0.04	-25%
Base/Acid	0.198		0.18		-9%
% Silica	80.18		82		2%

Table 12: Ranks of Coal as Classified by the American Society for Testing and Materials (ASTM)

rank and group	fixed carbon percentage (dry, mineral-matter-free basis) equal to or greater than	less than	volatile matter percentage (dry, mineral-matter-free basis) equal to or greater than	less than	British thermal units per pound equal to or greater than	less than ca (moist, minera
Anthracitic						
Meta-anthracite	98	. . .	. . .	2	. . .	. . .
Anthracite	92	98	2	8	. . .	. . .
Semianthracite**	86	92	8	14	. . .	. . .
Bituminous						
Low-volatile bituminous	78	86	14	22	. . .	. . .
Medium-volatile bituminous	69	78	22	31	. . .	. . .
High-volatile A bituminous	. . .	69	31	. . .	14,000	. . .
High-volatile B bituminous	. . .	. . .	. . .	. . .	13,000	14,000
High-volatile C bituminous	. . .	. . .	. . .	. . .	11,500	13,000
					10,500	11,500
Subbituminous						
Subbituminous A	. . .	. . .	. . .	. . .	10,500	11,500
Subbituminous B	. . .	. . .	. . .	. . .	9,500	10,500
Subbituminous C	. . .	. . .	. . .	. . .	8,300	9,500
Lignitic						
Lignite A	. . .	. . .	. . .	. . .	6,300	8,300
Lignite B	. . .	. . .	. . .	. . .	. . .	6,300

[Source: Encyclopedia Britannica Online]

Evaluation Timeline for Spring Creek Coal

Bid Received: May 11, 2004
Start Date: June, 2004 – RFP Evaluation Complete and interest expressed in Spring Creek coal

Global Assumptions:

- All analysis on the use of a 20% PRB coal blended with Central Appalachian coal has been complete (includes 3rd party engineering study, short and long-duration test burns, etc.)
- Capital upgrades per Order PSC-07-0816-FOF-EI were completed prior to start date for scenarios
- Environmental Permit to burn up to a 20% blend of sub-bituminous coal is effective prior to the start date for scenarios.

Low Fuel Case

JUN 2004	Vista Model & Internal Evaluation - "Paper Trial"
JUN/JUL 2004	Benchmarking with other utilities *May be concurrent with internal evaluation depending on utility availability.*
Significant issues with operations, fuel handling or environmental performance are not anticipated.	
AUG 2004	Order Fuel & Schedule Test Burn
OCT 2004	Conduct 3-day Test Burn
NOV 2004	Evaluation of test data and boiler investigation
NOV - DEC 2004	Based on test burn – determine any potential operational, fuel handling or environmental impacts
No significant operational or fuel handling issues occurred during test burn and there are no identified environmental impacts.	
JAN 2005	Determine any minor modifications or procedure updates needed to burn this blend
FEB – APR 2005	Implementation of modifications and procedure development – provide operator training on unique aspects of new fuel
MAY – JUL 2005	At this point, a 3-month test burn *may* be performed if modifications or new procedures warrant additional investigation of long-term performance before a final commitment for long-term purchase of fuel.
MAY or AUG 2005	Ready to burn new blend if economically prudent.

Medium Fuel Case

JUN 2004	Vista Model & Internal Evaluation - "Paper Trial"
JUN/JUL 2004	Benchmarking with other utilities *May be concurrent with internal evaluation depending on utility availability*
Potential issues with operations, fuel handling or environmental performance have been identified due to coal composition, coal quality characteristics or from benchmarking analysis.	
AUG 2004 – JAN 2005	Initiate 3rd Party Engineering Study *Includes: Preparing RFP for vendors, review of proposals, award contract, perform study, boiler inspection (outage required), design modification recommendations, final presentation*
FEB 2005	Perform Economic Analysis for blend
MAR 2005	Determine impacts with newly issued CAIR & CAMR regulations
Still economically viable to invest capital in equipment	
APR 2005	Establish project team & develop test protocol
MAY 2005	Implement minor modifications to accommodate 3-day test burn
MAY 2005	Order Fuel & Schedule Test Burn
JUN 2005	Conduct 3-day Test Burn *Testing dates are dependent on unit availability – may not be viable during critical peak periods*
JUL - AUG 2005	Evaluation of test data and boiler investigation & determine potential environmental impacts
Assumes no additional permitting needed for fuel blend or equipment	
SEP 2005	Review/Revise capital project scope – prepare RFP for equipment
OCT – NOV 2005	Issue equipment RFP – review proposals
DEC 2005	Order equipment *Assumes a 4 month lead time, some equipment has a 6-9 month lead time – this would dictate a Spring or Fall outage for installation.*
	Order Fuel & Schedule Test Burn
APR 2006	Spring outage to install equipment
APR 2006	Revise test protocol for longer test burn
MAY 2006	Provide operator training on unique aspects of new fuel and new equipment
JUN – AUG 2006 *(possible delay for test burn due to summer peak runs)*	Conduct 3-Month Test Burn *Monitor for longer-term boiler performance, fuel handling and emissions problems – May want to vary blend ratios (10%, 12%, 15%, 18%) for sensitivity analysis, if possible. Testing dates are dependent on unit availability – may not be viable during critical summer peak periods.*
SEP 2006	Review test burn data and determine long-term fuel blend feasibility
OCT 2006	Determine any additional modifications or procedures that need to be updated to burn this blend
NOV – DEC 2006	Implementation of modifications and procedure development – provide operator training on unique aspects of new fuel and new equipment
JAN – JUL 2007	At this point, a long-term test burn for 6-12 months *may* be performed if modifications or new procedures warrant additional investigation of long-term performance before a final commitment for long-term purchase of fuel.
Sometime After JAN 2007	Ready to burn new blend if economically prudent.

High Fuel Case

JUN 2004	Vista Model & Internal Evaluation - "Paper Trial"
JUN/JUL 2004	Benchmarking with other utilities *May be concurrent with internal evaluation depending on utility availability*
Potential for significant issues with operations, fuel handling or environmental performance have been identified due to coal composition, coal quality characteristics or from benchmarking analysis.	
AUG 2004	Engage EHSS with permit review to identify any potential emission increases
AUG 2004 – JAN 2005	Initiate 3rd Party Engineering Study *Includes: Preparing RFP for vendors, review of proposals, award contract, perform study, boiler inspection (outage required), design modification recommendations, final presentation*
FEB 2005	Perform Economic Analysis for blend
MAR 2005	Determine impacts with newly issued CAIR & CAMR regulations
Still economically viable to invest capital in equipment	
Potential for air emission (fugitive or point source) increases identified	
APR 2005	Apply for air construction permit for a short-term test burn
APR 2005	Establish project team & develop test protocol
JUN 2005	Permit issued with conditions for test burn
JUN 2005	Order Fuel & Schedule Test Burn
JUN 2005	Implement minor modifications to accommodate 3-day test burn
JUL 2005	Conduct 3-day Test Burn *Testing dates are dependent on unit availability – may not be viable during critical peak periods*
AUG – SEP 2005	Evaluation of test data and boiler investigation & determine potential environmental impacts
OCT 2005	Review capital equipment needed *Major modifications may trigger New Source Review (NSR) considerations and pollution control equipment installations / modifications (i.e. SO_3 conditioning system or ESP modifications) will require a construction permit.*
OCT 2005	Apply for air construction permit (if needed) *May take 9 - 15 months for final permit*
NOV 2005	Review/Revise capital project scope – prepare RFP
No air construction permit needed, or if needed, then received letter of intent to issue permit from FDEP	
DEC 2005 – JAN 2006	Issue equipment RFP – review proposals
JAN 2006	Order equipment *Assumes a 4 month lead time, some equipment has a 6-9 lead time – this would dictate a Spring or Fall outage for installation.*
MAR 2006	Order Fuel & Schedule Test Burn
Received final air construction permit for new equipment before installation can occur (if needed)	
MAY 2006	Spring outage to install equipment
MAY 2006	Revise test protocol for longer test burn
JUN 2006	Provide operator training on unique aspects of new fuel and new equipment
SEP – NOV 2006 *(expected delay for test burn due to summer peak runs)*	Conduct 3-Month Test Burn *Monitor for longer-term boiler performance, fuel handling and emissions problems – May want to vary blend ratios (10%, 12%, 15%, 18%), if possible. Testing dates are dependent on unit availability – may not be viable during critical summer peak periods.*
DEC 2006	Review test burn data and determine long-term fuel blend feasibility
JAN 2007	Determine any additional modifications or procedures that need to be updated to burn this blend
FEB – MAR 2007	Implementation of modifications and procedure development – provide operator training on unique aspects of new fuel new equipment
APR – SEP 2007	At this point, a long-term test burn for 6-12 months *is recommended* to ensure long-term performance before a final commitment for long-term purchase of fuel.
OCT 2007	Ready to burn new blend if economically prudent.

Evaluation Timeline for Indonesian Coal

Bids Received: February 15, 2006
Start Date: March, 2006 – RFP Evaluation Complete and interest expressed in one of the Indonesian coals
(Additional time would be needed to evaluate both)

Global Assumptions:

- All analysis on the use of a 20% PRB coal blended with Central Appalachian coal has been complete (includes 3rd party engineering study, short and long-duration test burns, etc.)
- Capital upgrades per Order PSC-07-0816-FOF-EI were completed prior to start date for scenarios
- Environmental Permit to burn up to a 20% blend of sub-bituminous coal is effective prior to the start date for scenarios.

Low Fuel Case

MAR 2006	Vista Model & Internal Evaluation - "Paper Trial"
MAR/APR 2006	Benchmarking with other utilities *May be concurrent with internal evaluation depending on utility availability*
Significant issues with operations, fuel handling or environmental performance are not anticipated.	
MAY 2006	Order Fuel & Schedule Test Burn
JUL 2006	Conduct 3-day Test Burn
AUG 2006	Evaluation of test data and boiler investigation
AUG - SEP 2006	Based on test burn – determine any potential operational, fuel handling or environmental impacts
No significant operational or fuel handling issues occurred during test burn and there are no identified environmental impacts.	
OCT 2006	Determine any minor modifications or procedure updates needed to burn this blend
NOV 2006 – JAN 2007	Implementation of modifications and procedure development – provide operator training on unique aspects of new fuel
FEB – APR 2007	At this point, a 3-month test burn *may* be performed if modifications or new procedures warrant additional investigation of long-term performance before a final commitment for long-term purchase of fuel.
JAN or APR 2007	Ready to burn new blend if economically prudent.

Medium Fuel Case

MAR 2006	Vista Model & Internal Evaluation - "Paper Trial"
MAR/APR 2006	Benchmarking with other utilities *May be concurrent with internal evaluation depending on utility availability*
Potential issues with operations, fuel handling or environmental performance have been identified due to coal composition, coal quality characteristics or from benchmarking analysis.	
MAY – OCT 2006	Initiate 3rd Party Engineering Study *Includes: Preparing RFP for vendors, review of proposals, award contract, perform study, boiler inspection (outage required), design modification recommendations, final presentation*
NOV 2006	Perform Economic Analysis for blend
DEC 2006	Determine impacts with newly issued CAIR & CAMR regulations
Still economically viable to invest capital in equipment	
JAN 2007	Establish project team & develop test protocol
FEB 2007	Implement minor modifications to accommodate 3-day test burn
FEB 2007	Order Fuel & Schedule Test Burn
MAR 2007	Conduct 3-day Test Burn *Testing dates are dependent on unit availability – may not be viable during critical peak periods*
APR - MAY 2007	Evaluation of test data and boiler investigation & determine potential environmental impacts
Assumes no additional permitting needed for fuel blend or equipment	
JUN 2007	Review/Revise capital project scope – prepare RFP for equipment
JUL – AUG 2007	Issue equipment RFP – review proposals
SEP 2007	Order equipment *Assumes a 4 month lead time, some equipment has a 6-9 month lead time – this would dictate a Spring or Fall outage for installation.*
	Order Fuel & Schedule Test Burn
FEB 2008	Spring outage to install equipment
FEB 2008	Revise test protocol for longer test burn
MAR 2008	Provide operator training on unique aspects of new fuel and new equipment
APR – JUN 2008 *(possible delay for test burn due to summer peak runs)*	Conduct 3-Month Test Burn *Monitor for longer-term boiler performance, fuel handling and emissions problems – May want to vary blend ratios (10%, 12%, 15%, 18%) for sensitivity analysis, if possible.* *Testing dates are dependent on unit availability – may not be viable during critical summer peak periods.*
JUL 2008	Review test burn data and determine long-term fuel blend feasibility
AUG 2008	Determine any additional modifications or procedures that need to be updated to burn this blend
SEP – OCT 2008	Implementation of modifications and procedure development – provide operator training on unique aspects of new fuel and new equipment
NOV 2008 – JUN 2009	At this point, a long-term test burn for 6-12 months *may* be performed if modifications or new procedures warrant additional investigation of long-term performance before a final commitment for long-term purchase of fuel.
Sometime After NOV 2008	Ready to burn new blend if economically prudent.

High Fuel Case

MAR 2006	Vista Model & Internal Evaluation - "Paper Trial"
MAR/APR 2006	Benchmarking with other utilities *May be concurrent with internal evaluation depending on utility availability*
Potential for significant issues with operations, fuel handling or environmental performance have been identified due to coal composition, coal quality characteristics or from benchmarking analysis.	
MAY 2006	Engage EHSS with permit review to identify any potential emission increases
MAY 2006 – OCT 2006	Initiate 3rd Party Engineering Study *Includes: Preparing RFP for vendors, review of proposals, award contract, perform study, boiler inspection (outage required), design modification recommendations, final presentation*
NOV 2006	Perform Economic Analysis for blend
DEC 2006	Determine impacts with newly issued CAIR & CAMR regulations
Still economically viable to invest capital in equipment	
Potential for air emission (fugitive or point source) increases identified	
JAN 2007	Apply for air construction permit for a short-term test burn
JAN 2007	Establish project team & develop test protocol
MAR 2007	Permit issued with conditions for test burn
MAR 2007	Order Fuel & Schedule Test Burn
MAR 2007	Implement minor modifications to accommodate 3-day test burn
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JUL 2007	Review capital equipment needed *Major modifications may trigger New Source Review (NSR) considerations and pollution control equipment installations / modifications (i.e. SO_3 conditioning system or ESP modifications) will require a construction permit.*
JUL 2007	Apply for air construction permit (if needed) *May take 9 - 15 months for final permit*
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No air construction permit needed, or if needed, then received letter of intent to issue permit from FDEP	
SEP – OCT 2007	Issue equipment RFP – review proposals
NOV 2007	Order equipment *Assumes a 4 month lead time, some equipment has a 6-9 lead time – this would dictate a Spring or Fall outage for installation.*
JAN 2008	Order Fuel & Schedule Test Burn
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APR 2008	Spring outage to install equipment
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MAY 2008	Provide operator training on unique aspects of new fuel and new equipment
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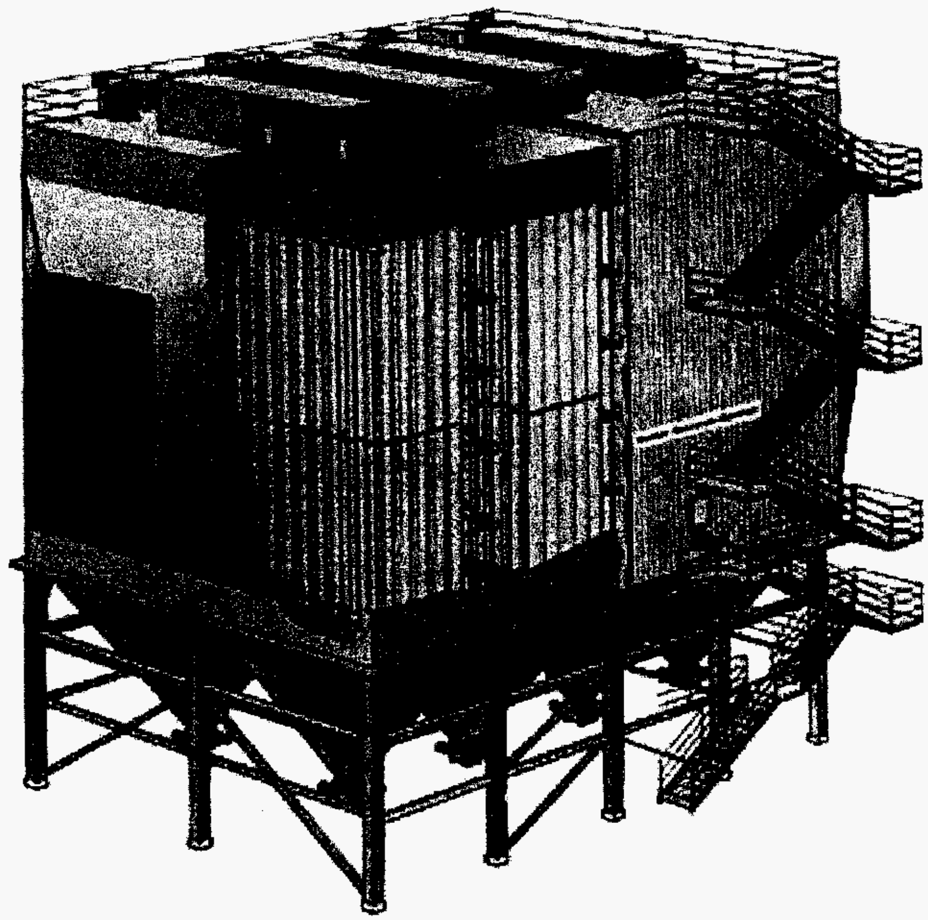
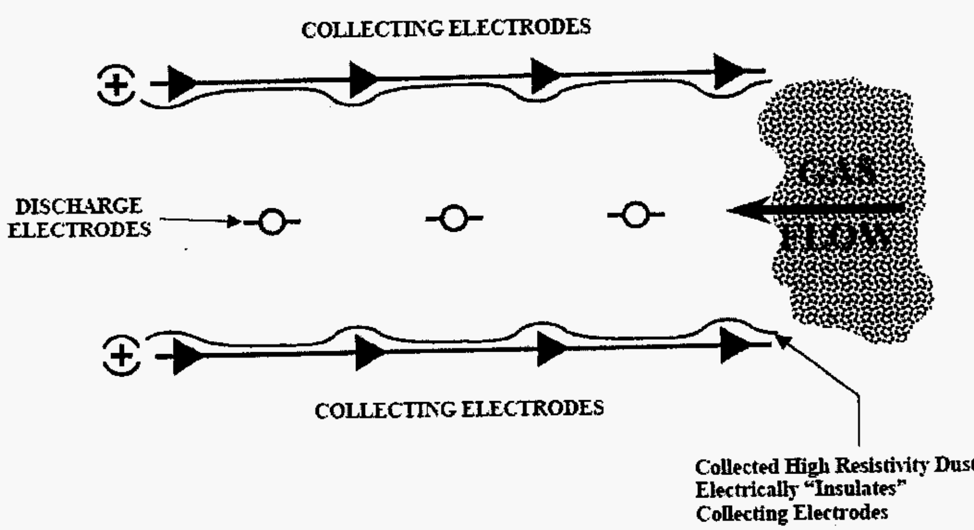
DEC 2008	Review test burn data and determine long-term fuel blend feasibility
JAN 2009	Determine any additional modifications or procedures that need to be updated to burn this blend
FEB – MAR 2009	Implementation of modifications and procedure development – provide operator training on unique aspects of new fuel new equipment
APR – SEP 2009	At this point, a long-term test burn for 6-12 months *is recommended* to ensure long-term performance before a final commitment for long-term purchase of fuel.
OCT 2009	Ready to burn new blend if economically prudent.

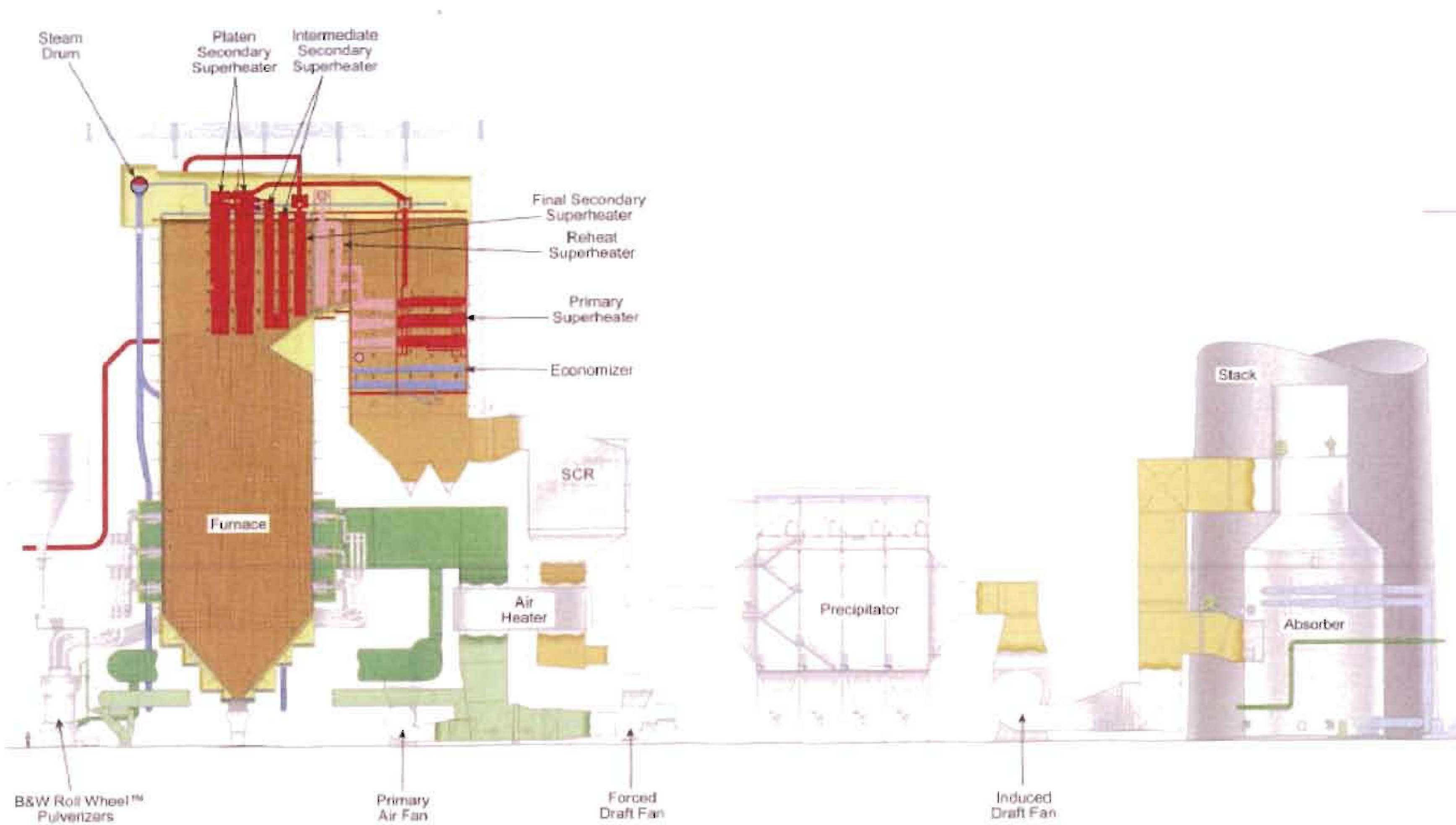
Electrostatic Precipitator (ESP) Diagrams





[Source: Hamon Research-Cottrel]

Unit Diagram



Modern 660 MW coal-fired utility boiler system with environmental control equipment.

The Babcock & Wilcox Company

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Progress Energy Florida
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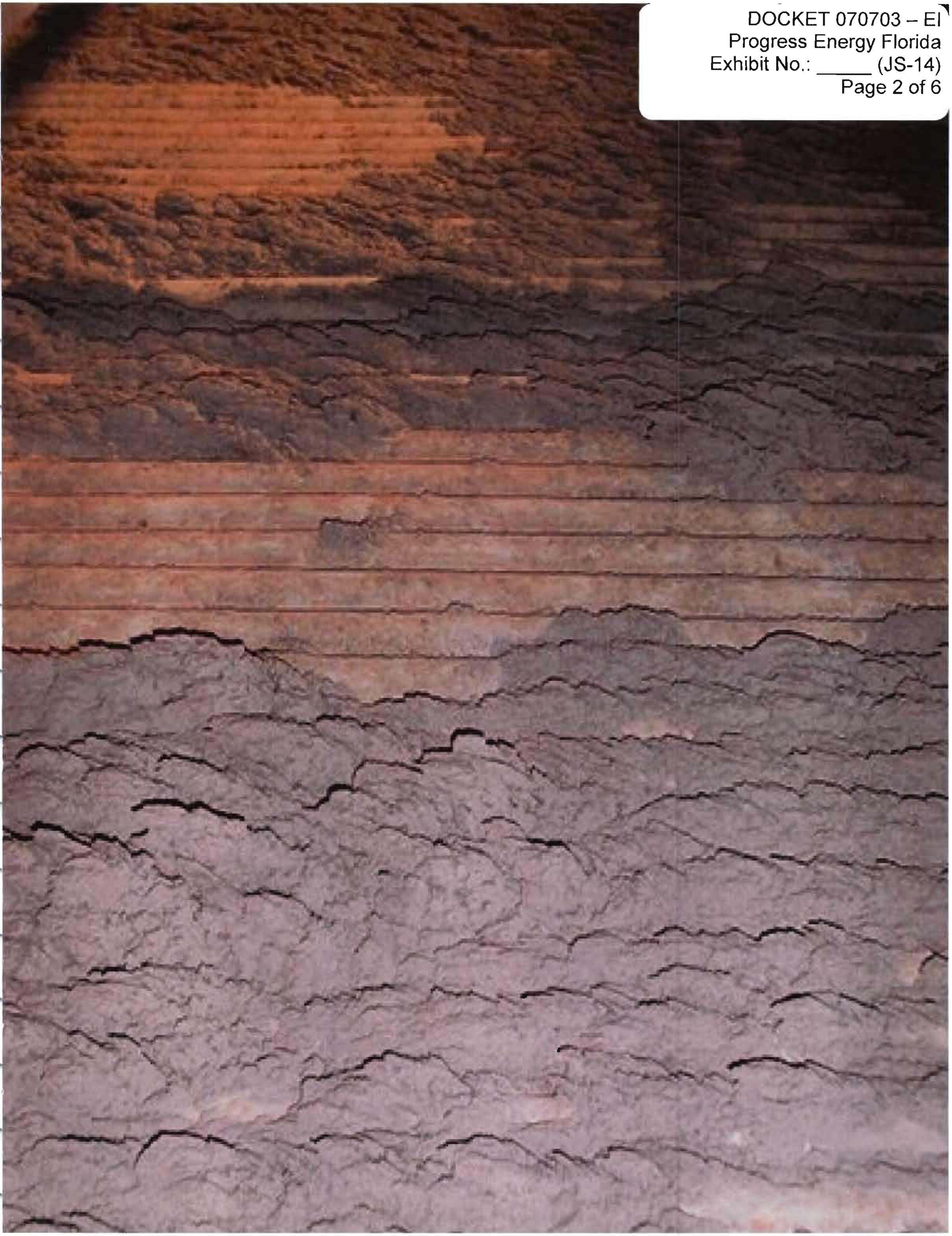
Page 1 of 6

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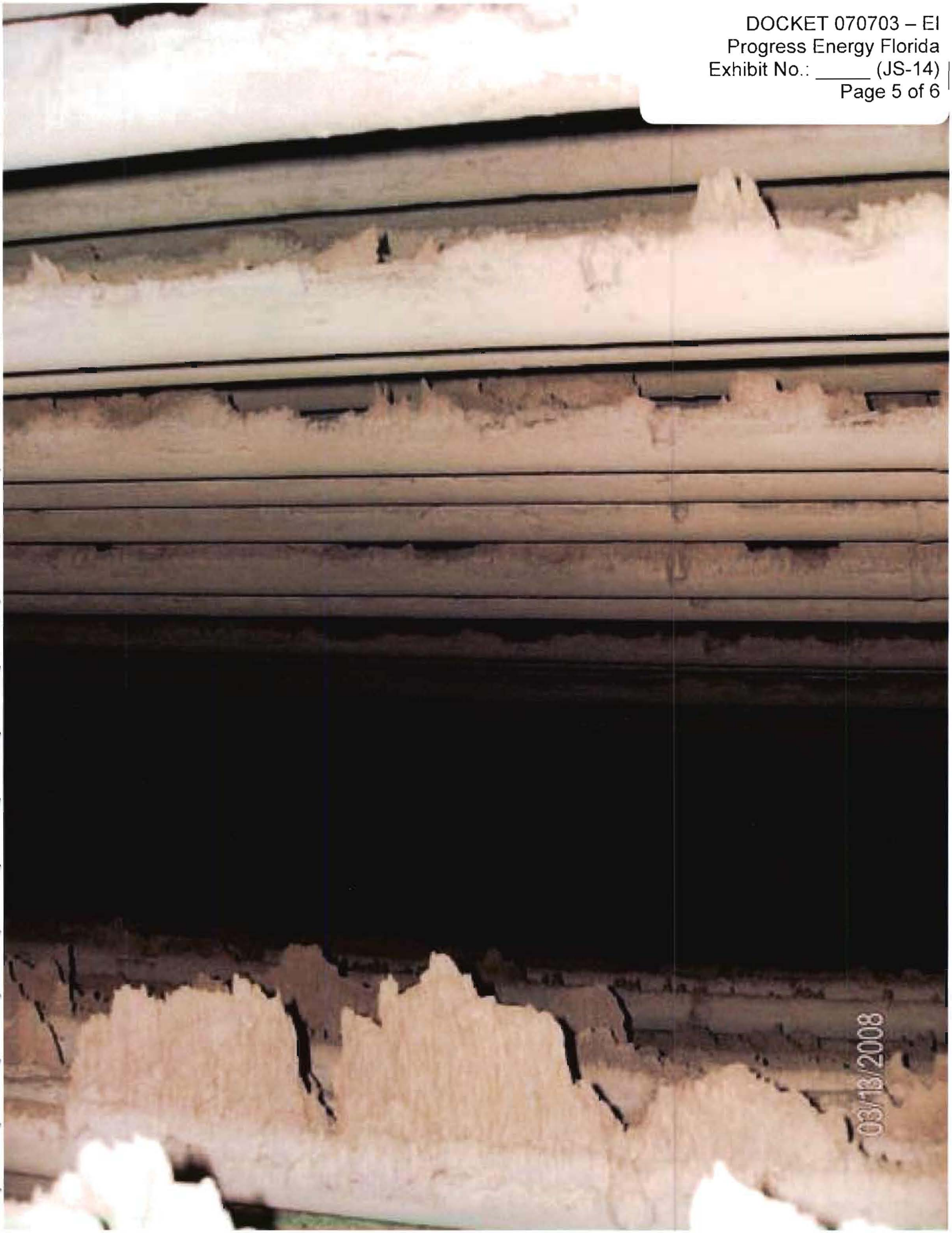
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