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November 3, 2006

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0870

Dear Ms. Bayo:

On October 19, 2006, our office filed, on a temporary, confidential basis, the direct testimony and exhibits of Robert L. Sansom in support of the Petition that Citizens filed on August 10, 2006. On the same date, Progress Energy Florida Inc. ("PEF") submitted a Notice of its intent to seek confidential classification of any confidential information that it found during its review of the testimony and exhibits.

Recently, the attorneys for PEF informed me that they have determined that the testimony and exhibits contain no confidential information. Yesterday, PEF withdrew its Notice. Accordingly, I am submitting, for filing and appropriate distribution, an additional 15 copies of the package containing Mr. Sansom's direct testimony and exhibits. To be clear, these are not confidential.

Thank you for your assistance.

Yours truly,

Joe A. McGlothlin

Joseph A. McGlothlin

CMP ______
COM 5
CTR orig
ECR ______
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OPC ______
RCA ______
SCR ______
SGA ______
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OTH Lockard - cover letter

Cc: Lisa Bennett
Parties of record

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Petition on behalf of Citizens of the State of Florida to required Progress Energy Florida, Inc. to refund customers $143 million

Docket No. 060658 - EI

TESTIMONY AND EXHIBITS OF

Robert L. Sansom

ON BEHALF OF THE

FLORIDA OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060658-EI

TESTIMONY OF ROBERT L. SANSOM

ON BEHALF OF CITIZENS OF THE STATE OF FLORIDA

Q. Please state your name and business address.

A. My name is Robert L. Sansom. I am President of Energy Ventures Analysis, Inc. My business address is 1901 N. Moore Street, Suite 1200, Arlington, VA 22209.

Q. Please describe your educational and business background.

A. I have about 30 years of experience in coal markets, coal procurement reviews and audits, coal transportation, coal suitability and coal plant environmental controls and emissions. This experience includes knowledge of the procurement practices of electric utilities that burn coal in the generation of electricity. My experience and educational background are summarized at Exhibit ____ (RS-1).

Q. For whom do you appear in this proceeding?

A. I am testifying on behalf of the Office of Public Counsel (OPC).

Q. Please describe the purpose for which OPC engaged you.

A. At first, I was engaged to assist OPC in its evaluation of prices that Progress Energy Florida Inc. paid for coal to fuel its Crystal River coal units for deliveries in 2005 and 2006. During the course of that initial work, matters came to light that led OPC to expand the scope of my engagement to include an investigation indications that PEF imprudently failed to obtain the most economical sources of coal to supply Crystal River Units 4 and 5 during the period 1996-2005. (During part of this period, PEF's predecessor, Florida Power Corporation, was in existence. For the sake of simplicity, I will refer to the predecessor entity and the current utility as PEF). Based on my findings, OPC filed the Petition of August 10, 2006 that is the subject of this proceeding. The purpose of my testimony is to provide the evidentiary basis for the Petition.

Q. **Please summarize your testimony regarding your analysis of PEF's fuel procurement activities during 1996-2005, as they related to Crystal River Units 4 and 5.**

A. In my testimony I will address and support these points:

(1) PEF designed and constructed Crystal Units 4 and 5 to have the ability to burn a blend of coals consisting 50% of bituminous coal and 50% of sub-bituminous coals in its boilers.

(2) PEF's initial fuel strategy was to provide bituminous coal from the Eastern states and sub-bituminous coal from Western states in equal quantities. However, when the units began commercial operations, PEF burned only bituminous coal in Units 4 and 5. During the early 1980's this practice had no adverse consequences for ratepayers, because bituminous coal was more economical than sub-bituminous coal.

(3) However, by the early 1990's developments in the mining and transportation of the coals led to sub-bituminous coal becoming the more economical choice. This information was widely disseminated within the coal and utility markets and industries at the time. Numerous utilities in the Midwest and Southeast shifted from bituminous coal

to sub-bituminous coal to take advantage of the clear opportunity to lower fuel costs that sub-bituminous coal afforded them. The same economic information regarding the availability of sub-bituminous coal from the Powder River Basin area of the West and the relative economics of the two coals that led these utilities to shift to sub-bituminous coal was known, or should have been known, to PEF in the same time frame.

(4) PEF ignored the information on which other utilities had acted. In fact, in 1996 PEF took steps to abandon its authority to burn sub-bituminous coal in Units 4 and 5 by omitting sub-bituminous coal from its application for the newly required federal Title V air permit. For a full decade after it should have shifted to a 50% Powder River Basin (PRB) sub-bituminous coal blend with bituminous coal, PEF continued to burn bituminous coal and a product of bituminous coal treated with oil called synthetic fuel or "synfuel." Frequently PEF purchased these fuels from companies in which its parent, Progress Energy Inc., held ownership interests. During that time frame, sub-bituminous coal was available from the Powder River Basin of Montana and Wyoming at delivered prices via the water route to Crystal River Units 4 and 5 cheaper than either the bituminous coal or the synfuel that PEF purchased.

(5) When PEF belatedly attempted to move towards bituminous coal in 2004, its earlier imprudent decision to omit sub-bituminous coal from its federal environmental permit and its repeated failures to conduct test burns complicated and delayed its ability to do so.

(6) As a result of its failure to maintain its flexibility under permits, conduct its procurement processes prudently and secure the most economical sources of coal for Crystal River Units 4 and 5, during the period 1996-2005 PEF passed fuel and fuel-

related costs through the fuel cost recovery clause that were excessive by the amount of $134.5 million. My calculation does not include interest on this amount.

Q. Please tell us how you have organized your testimony.

A. I will begin with a brief overview and discussion of the nature and properties of bituminous and sub-bituminous coals, the sources of those coals, and the implications of the differences between them for electric utilities that burn coal. I will then discuss the design and construction of Crystal River Units 4 and 5. Next, I will identify the developments in the mining and transportation of sub-bituminous coal from the Powder River Basin region of the West that profoundly altered the cost relationships between the two coals and affected the economic choices of consumers of coal in the early 1990's. I will show how a move to exploit the dramatic cost advantages of Powder River Basin coal swept the electric industry in the Midwest and Southeast. I will then discuss how, by contrast, PEF ignored these developments, continued to burn fuel that had become more expensive than an available alternative, and even abandoned its ability to acquire and burn Powder River Basin coal. I will provide information that suggests strongly that its motivation for doing so was to contribute to its parent company's overall profitability at the expense of its ratepayers. In the final section, I will discuss the methodology that I applied to calculate the extent of PEF's overcharges, and quantify that amount.

SECTION I

OVERVIEW OF WESTERN AND EASTERN COALS

Q. Please explain the terms "bituminous" and "sub-bituminous" coals.

A. These terms are used to identify two kinds of coals having different physical properties. In the United States, bituminous coal is found generally in the Appalachian states (lower sulfur) and the Illinois Basin (higher sulfur). Bituminous coal derives its name from the relatively heavy concentration of "bitumen," a hydrocarbon, that it contains. When it is burned, bituminous coal releases approximately 11,500 to 13,000 British thermal units (Btus) of heat per pound of coal. It has a moisture content of approximately 5 to 10%, and its ash content is approximately 10%. Generally, "minable" bituminous coal is found in seams ranging in thickness from 4 to 12 feet. Much of this bituminous coal lies hundreds of feet below the surface, meaning that underground mining must be employed to remove it.

"Sub-bituminous coal" is the term used to identify a type of coal that has a lesser content of bitumen than that of bituminous coal. In the United States, sub-bituminous coal is found in huge deposits in the Powder River Basin area of Montana and Wyoming. Whereas bituminous coal is found in thin seams, in the Powder River Basin sub-bituminous coal occurs in deposits ranging from 30 feet to more than 110 feet thick. Powder River Basin coal lies close to the surface. It is mined by removing the overburden and scooping the coal from the surface. The first sub-bituminous coal that was opened for mining in Wyoming in the late 1960's and early 1970's contained approximately 8,200 to 8,450 Btus per pound of coal. Subsequently, when areas south of that region were opened for mining, deposits containing upwards of 8,800 Btus per pound of coal were discovered.

Sub-bituminous coal has a greater moisture content and lower ash content than its bituminous counterpart. Sub-bituminous coal contains far less sulfur than even "low sulfur" bituminous coal. Sub-bituminous coal typically contains approximately 0.4% sulfur, or roughly half as much as "low sulfur" Appalachian bituminous coal.

Q. Are there any other differences?

A. Yes. The differences in composition cause the two coals to handle differently. Principally, compared to bituminous coal, sub-bituminous coal generates more dust that must be controlled. Also because of its characteristics, it must be stored in stockpiles more carefully than bituminous coals.

SECTION II

DESIGN OF CRYSTAL RIVER UNITS 4 AND 5

Q. How do electric utilities deal with the differences in the properties of bituminous and sub-bituminous coals?

A. Principally by taking the properties of the coals the units will burn into account when designing the units. In addition, operating and maintenance procedures are tailored to the type of coal that is being burned.

Q. Please provide some examples of how a unit that will burn sub-bituminous coal would be designed differently than one in which the utility's management intends to burn only bituminous coal.

A. The boiler furnace is larger, pulverizers and coal conveyance and storage facilities are sized for more tonnages, and upgraded dust controls are installed.

Q. **How would operating and maintenance protocols differ?**

A. More care is taken with coal handling and storage and more tons are moved.

Q. **Were Crystal River Units 4 and 5 designed with a particular kind of coal in mind?**

A. Yes. Crystal River Units 4 and 5 were designed to burn a mixture of the two coals containing 50% subbituminous Powder River Basin (PRB) coal. Babcock & Wilcox (B&W) designed the boiler to burn 50% PRB coal and the firm Black & Veatch specified a 50% blend as the design coal for Crystal River Units 4 and 5. (See Exhibit__(RS- 2.)) More precisely, Babcock and Wilcox specified, as the "design basis" coal for Units 4 and 5, a blend containing 50% sub-bituminous coal at 8,125 Btu/lb and 50% bituminous coal at 12,450 Btu/lb for an average 10,285 Btu/lb blended coal (see B&W 1978 Exhibit__(RS_ 2)).

Q. **What is the significance of the fact that those who designed Units 4 and 5 specified the 50/50 blend as the "design basis" fuel?**

A. The specification is important because the size of the boiler furnace, its convection passes, pulverizers, coal storage and feed systems, ash handling and disposal systems, and particulate removal systems, were all designed and constructed so as to be able to accommodate this "design coal". In fact, as Exhibit 2 states, Babcock and Wilcox guaranteed that the units' boilers would operate to specifications if the "design basis" coal were burned in the boilers. This means that the units were designed and intended to operate on the 50/50 blend with no adverse effects, and without the necessity of plant modifications. This will take on added significance in the section in which I will address my calculation of overcharges.

Q. Was PEF's initial fuel strategy for Crystal Units 4 and 5 consistent with PEF's design decisions and construction activities??

A. Yes. In 1978 PEF represented to the Department of Environmental Regulation and to the Governor and Cabinet, sitting as the Florida Electrical Power Plant Siting Board, that the Crystal River Units 4 and 5 units would burn 50% Western (PRB) coal delivered by barge to Crystal River and 50% Central Appalachian (bituminous) coal delivered by rail (see Exhibit__(RS- 3)). Crystal River 4 began operating in 1982 and Crystal River 5 in 1984.

Q. Did PEF indicate at the time that it would blend the two coals at the Crystal River site?

A. Yes. PEF's application for site certification of Crystal River Units 4 and 5 (3/17/80) describes the coal yard as including "a coal blending facility" and states "at the storage area coal will be blended and transferred to the crusher house by covered conveyor". (See Exhibit__(RS- 4), excerpts from Crystal River Units 4 and 5 Site Certification Application by FPC 3/17/80 pp 3-9 to 3-21, 3-81 to 3-88.

Q. Did PEF represent in this document that Wyoming Powder River Basin ("PRB") coal would be 50% of the blend?

A. Yes. In addition, PEF's submittal described, in the air emissions section, the additional dust emissions from PRB subbituminous coal and the controls required. (See Exhibit__(RS- 4) p. 3-84.)

Q. In summary, then, the Crystal River Units 4 and 5 facility was designed and built to burn a 50/50 PRB/bituminous coal blend?

A. Yes. The ratepayers have been paying for this capability since units 4 and 5 became part of PEF's rate base in the early 1980's.

Q. Is there other evidence these units are capable of burning PRB coal?

A. Yes. The Crystal River Units 4 and 5 B&W units are "sister units" to the B&W units at Detroit Edison's Belle River two unit plant and at Alabama Power's Miller four unit plant 20 miles northwest of Birmingham.

Q. What coals are used at Miller and Belle River?

A. Belle River has always burned 100% PRB coal. Miller Units 4 burned 100% PRB coal in 1995, and by 1997 all four Miller units were burning 50% PRB coal.

SECTION III

PRB COAL PRODUCTION AND TRANSPORTATION DEVELOPMENTS IN THE EARLY 1990s

Q. When Crystal River Units 4 and 5 began commercial operations, did PEF follow the fuel strategy that it had outlined to the regulators?

A. No. Beginning with the time the units became operational, PEF has fueled them solely with bituminous coal. In fact, in answers to discovery PEF told OPC that, prior to 2004, PEF had not even tested a blend of sub-bituminous and bituminous coal in the units at any time.

Q. In this proceeding, do you recommend any refunds or adjustments based on PEF's use of bituminous coal exclusively in Crystal River 4 and 5 during the first years of their operation?

A. No. During the early 1980s, the comparative economics were such that the use of bituminous coal exclusively did not adversely impact PEF's ratepayers.

Q. What do you mean by "comparative economics?"

A. When identifying the most economical choice of coals, PEF—or any utility—must take into account the "delivered cost" per unit of heat, usually expressed in units of dollars per million Btus (mmBtus), of each candidate fuel.

Q. What is "delivered cost?"

A. The cost of generating electricity with coal includes—not only the commodity—but the cost of transporting it from the mine to the site of generation. For this reason, in an economic comparison the cost of transportation is added to the cost of the coal itself. The sum is then divided by the heat content of the coal (total Btus) to derive the cost of coal per million Btus for the sake of comparisons.

Q. You refer to the cost of coal per million Btus of heat. Why do you not compare the cost of one ton of bituminous coal, delivered, to the delivered cost of a ton of sub-bituminous coal?

A. Because of the differences in the amount of heat stored in each coal, a simple ton-to-ton comparison would not be meaningful. A utility is in the business of converting the thermal or heat energy residing in the coal into electrical energy. The heat released by burning coal in the boiler produces steam, which turns a turbine, which drives a generator. In comparing coals, then, one must look to the heat content of each. If one ton of sub-bituminous coal contained precisely the same number of Btus of heat as one ton of bituminous coal, an examination of quantities, tons and $/ton, would be the appropriate apples-to-apples comparison. However, as I described earlier, a pound of sub-bituminous coal contains fewer Btus than does a pound of bituminous coal. It follows that a utility must burn a greater quantity of sub-bituminous coal to derive the number of needed Btus than if it were burning bituminous coal.

To take the example farther: Assume that the cost of a ton of sub-bituminous coal containing 8,400 Btus per pound of coal is $50, and the cost of a ton of bituminous coal rated at 12,000 Btus per pound is also $50. Assume also that the cost of transportation (and any other costs) are identical for the two coals. Clearly, this is not a "tie," because the utility would have to burn more than a ton of sub-bituminous coal—and therefore pay more than $50—to derive the same number of Btus that it would obtain from a $50 ton of bituminous coal. Therefore, comparing the price of a pound, or ton, of sub-bituminous coal to a corresponding quantity of bituminous coal would not provide a meaningful comparison of the relative costs of producing electricity. Converting each into delivered costs per million Btus places the two coals on an equal and comparable footing. Note that, as the number of Btus in a given quantity of sub-bituminous coal increases, the cost of sub-bituminous coal per million Btus goes down, and its position in the economic comparison with bituminous coal becomes more favorable.

Q. Why was PRB coal not competitive with Eastern bituminous coal in the 1980s?

A. I mentioned earlier that the first Wyoming PRB sub-bituminous coal contained about 8200 to 8450 Btus per pound. This placed it at a disadvantage when compared to the alternative of higher Btu bituminous coal, even though the price per ton of commodity was cheaper than Eastern bituminous coal (mining thick deposits from the surface is obviously less expensive than deep underground mining of thin seams).

. In addition, during the early 1980s the Burlington Northern railroad was the sole means of transporting Powder River Basin coal by rail. In the absence of competition, transportation costs were high. When these considerations were translated into the economic analysis that I have described, for a period of time PRB coal was more expensive for many destinations than bituminous coal on a "delivered" basis,

Q. What, if anything, changed by the early 1990s?

A. Two developments improved the economics of PRB coal to the Southeast in the early 1990's:

1. The entry of the C&NW as an originating PRB rail carrier in 1985 and the acquisition of the C&NW by the Union Pacific in the early 1990's to constitute a competitive carrier to the Burlington Northern (later the BNSF). The competition applied to the transportation of PRB coal to east of the Mississippi River rail-

destinations and to the Mississippi and Ohio Rivers for transloading at River docks, and "all rail" to a Mobile, Alabama dock that made it available for ocean barge movement to Crystal River Units 4 and 5.

2. The development and expansion in the southern Powder River Basin of Wyoming of so-called high Btu/lb subbituminous coal mines capable of shipping 8,800 Btu/lb Powder River Basin coal. In 1990 the southern PRB mines produced 76 million tons of this higher Btu content PRB coal. By 1997, they increased their production to 212 million tons annually, a phenomenal increase of 136 million tons annually over a period of only seven years. See Exhibit__(RS- 5). In 1998 the PRB high Btu/lb "Joint Line" mines (i.e., those mines in locations served by both rail carriers) shipped coal to utilities that averaged 8,736 Btu/lb. This compares to the 8,150 Btu/lb that the designers of Crystal River Units 4 and 5 assumed for PRB coal in the late 1970s. The higher (relative to the design standard) Btu content PRB coal poses an advantage, because fewer tons would have to be purchased, handled and burned to derive the needed Btus.

Q. Have these developments been documented?

A. Yes. I have attached, as my .Exhibits ____(RS-5) and ____(RS-6), references to several documents that describe these developments in considerable detail. The documents include cover sheets of voluminous studies and reports prepared by or for the Electric Power Research Institute (EPRI), an association of electric utilities, and the Department of Energy/Energy Information Agency. The developments are not subject to dispute.

Q. Were these developments the subject of attention in the electric industry at the time they were occurring??

A. Yes. They were widely reported contemporaneously in the professional and trade press.

Q. What was the price of this 8,800 Btu/lb coal per ton FOB mine in the early 1990s?

A. Less than $5.00/ton. See Exhibit ____ (RS-7).

Q. What was the cost to transport the coal by rail to the Mississippi River at St. Louis or lower Ohio River in Illinois?

A. $10 to $12/ton, including transloading-to-barge charges.

Q. Is there any evidence that the availability and price of the higher Btu content PRB coal were known to utility coal buyers in the early-to-mid 1990s?

A. Yes. Utilities were the only significant buyers of higher Btu content Powder River Basin sub-bituminous coal in that time frame. Please refer to Exhibit ____ (RS-8), a map of the U.S. showing 1996 PRB coal deliveries as a percent of total burn by state of destination.

Q. How did Southeastern electric utilities other than PEF respond to these developments?

A. In the early 1990s, the major Southeastern coal burning utilities engaged in a serious and comprehensive process to examine increased utilization of Powder River Basin coal, conduct test burns, and introduce PRB coal where it was the economic choice. By 1998

Alabama Power was burning 6 million tons per year of PRB coal at Miller, Georgia Power was burning 6.2 million tons per year of PRB coal at Scherer 3 and 4, and TVA was burning 3.7 million tons per year at several plants, none of which had been designed to burn PRB coal. TECO burned PRB coal in significant quantities at Gannon beginning in 1996.

Q. Is it important to distinguish between units designed to burn Powder River Basin (either at 100% or in a blend) coal and those designed to burn 100% bituminous coal?

A. Yes, because in this case, Crystal River Units 4 and 5 were designed to burn 50% PRB coal. It is simpler to burn PRB coal in a unit designed for it as opposed to using PRB coal in units not designed to burn it.

Q. Have you prepared a table that describes the PRB purchases by Alabama Power, Georgia Power, Mississippi and Gulf Power, and TECO?

A. Yes, see Exhibit ____ (RS-9).

Q. How do the plants listed above receive PRB coal?

A. Scherer, Miller and Daniel receive PRB coal by all-rail; Watson by rail to Mobile and barge to the plant; Gannon PRB coal traveled by BNSF rail to Cook Terminal in southern Illinois on the Ohio River near its confluence with the Mississippi River, then by barge to Electro Coal Terminal and by ocean barge to Gannon.

Q. What were the delivered prices of these coals?

A. They are shown as reported in Exhibit ____ (RS-10). These are substantially lower delivered prices in $/MMBtu than Central Appalachian (CAPP) coal delivered to other power plants in the vicinity of these plants.

Q. When did Georgia Power test burn PRB coal at Scherer?

A. In 1989, 1990 and 1991 over 2 million tons of PRB coal were burned at Scherer.

Q. When did Georgia Power solicit PRB bids and sign a rail contract and coal supply agreements to supply Scherer with PRB coal?

A. In 1993.

Q. Is this Commission informed about the fuel cost at Scherer?

A. Yes. FP&L owns 75% of Scherer 4 and JEA 25%. Fuel costs to Scherer are reported to the Commission in FP&L's "A" Schedules. In fact, in November 1995 FP&L asked the FPSC to keep this information confidential. In 1996 the Commission rejected FP&L's request.

Q. How was PRB coal blended for Watson?

A. In 1996 Mississippi Power blended test shipments containing 20% PRB coal at McDuffie Terminal and later at Plant Watson. (<u>Coal Week</u>, December 9, 1996, p. 7.) PRB coal was burned in a blend at Watson for three years 1997-1999. It was later displaced by bituminous imported coal. Watson was not designed to use PRB coal.

Q. Were these uses of PRB coal at Scherer, Miller, Daniel, Gannon and Watson economic?

A. Yes. Gulf Power told this Commission in 1996 that PRB coal burns at Daniel resulted in "dramatic savings" (see Coal Week, April 22, 1996); at Miller, the shift to 100% PRB coal in a unit like Crystal River Units 4 and 5 saved millions of dollars and was not accompanied by a derate. (See Coal Week, September 23, 1996, p. 3 at Exhibit ____ (RS-11).)

Q. Were these examples of the successful and economic utilization of PRB coal in the Southeast known generally in the coal and utility industries?

A. News of these uses, test burns, accompanying PSC testimony, and FERC data were public and were widely disseminated at the time of the developments in the trade press, in professional publications, and at conferences and technical meetings. In the 1990's these publications included Coal Outlook and Coal Week. Later the publications included Argus Coal Daily and Platt's Coal Trader International, United Power's weekly price sheet, Platt's Coal Outlook, and SNL Energy's Coal Report. Plus, the utilities—*including PEF*—saw the impact of the economic shifts first hand when they conducted solicitations for offers to supply coal and received bids from producers of PRB coal.

Q. **During the time frame 1996-2005, did any of the publications that you mentioned provide information on then current market prices of PRB coal and bituminous coal? If so, how frequently were the market prices reported?**

A. Yes. During the 1990s, Coal Outlook, for instance, published such market prices weekly. After 2000, the Platt's publication reported such market prices on a daily basis. Market price information was readily available to the industry at the time.

SECTION IV

RESPONSE OF PEF TO DEVELOPMENTS IN PRB AND BITUMINOUS MARKETS

Q. Please describe the manner in which PEF structured its means of supplying Crystal River Units 4 and 5 with coal prior to the advent of economical PRB coal.

A. PEF's parent holding company had established prior to 1996 a web of affiliates to mine Central Appalachian (CAPP) bituminous coal, to transload CAPP coal at company owned docks from truck and rail to river barge on the Kanawha, Big Sandy, and Upper Ohio Rivers, to own river barges which moved this coal down the rivers to New Orleans, to transload at New Orleans (IMT) to Gulf barges, which were also partly owned by PEF affiliates. PEF contracted with its sister company, now called Progress Fuels Corporation, to serve as PEF's coal procurement arm. Progress Fuels Corporation owned subsidiaries in the coal mining and transportation businesses. Progress Fuels Corporation's "procurement department", acting as the utility's coal supplier, dealt frequently with Progress Fuels Corporation's marketing division during procurement activities.

Q. How did PEF respond to the developments in the coal markets that you described earlier?

A. PEF ignored the changes. In fact, PEF's actions were worse than that. At the same time other utilities were lowering fuel costs by switching to PRB coal, PEF inexplicably, unilaterally surrendered its authority under environmental permits to burn PRB coal. PEF continued to purchase bituminous coal, much of which the purchasing arm of its affiliate, Progress Fuels Corporation, bought from the marketing arm of its affiliate, Progress Fuels Corporation, even though PRB coal—and, on certain occasions, imported bituminous coal—were cheaper than the Appalachian bituminous coal and synfuel that PEF burned at Crystal River Units 4 and 5.

<u>Permitting</u>

Q. Please explain how PEF surrendered its ability to burn PRB coal at Crystal River Units 4 and 5.

A. Based on PEF's presentation, the Electrical Power Plant Siting Board issued a certification order that authorized PEF to burn the 50/50 "design coal" at Crystal River Units 4 and 5. The Board issued the order in 1978, and the plants became operational in the early 1980s. In the mid-1990s, as the result of amendments to federal environmental statutes, PEF and other utilities were required to apply for and obtain a new permit, called the "Title V operating permit." When PEF applied for this permit, it omitted sub-bituminous coal from the fuels for which it asked authority to burn in Crystal River Units 4 and 5. It did this despite the fact that Units 4 and 5 were designed to burn PRB coal, despite PEF's initial coal strategy, and despite the wave of utilities responding to changed economics of coal procurement by shifting to PRB coal.

Q. What reason did PEF give for omitting sub-bituminous coal from the application for its Title V permit?

A. In an answer to one of OPC's interrogatories, PEF said that at the time it did not contemplate the burning of sub-bituminous coal. See Exhibit _____ (RS-29).

Q. Do you find this explanation satisfactory?

A. No. It was folly for PEF to abandon its authority to use the capability designed into the units. This would have been the case even if preserving the ability was needed only to prepare for future contingencies. The wealth of available information regarding the developments in the coal markets makes the omission incomprehensible.

Q. Was PEF, through its affiliate, soliciting PRB coal for Crystal River Units 4 and 5 during the period 1995 to 2004?

A. Yes. I am aware that PEF, through the affiliate whom PEF contracted to purchase coal for Crystal River Units 4 and 5, solicited PRB coal in 1995, 1998, 2001, 2003 and 2004.

Q. Why?

A. Apparently because the fuel procurement personnel realized Crystal River Units 4 and 5 was physically capable of burning PRB coal and because the fuel procurement personnel did not become aware of the omission of sub-bituminous coal from the Title V permit until after they had ordered a quantity of PRB coal for a test burn in 2004. In other words, the left hand did not know what the right hand was doing.

Q. Yet PEF applied for a Title V Air Permit in March of 1996 that excluded PRB coal?

A. Yes, the original application requests a Title V permit for "bituminous" coal only, not subbituminous coal. (See Exhibit ___ (RS-28).)

Q. When was this permit issued?

A. The permit did not become effective until January 1, 2000.

Q. Does this mean under its pre-existing permits, PEF could have purchased PRB coal from 1996-1999 when it was the most economic alternative, notwithstanding the omission in its 1996 application?

A. Yes. I have been informed by Counsel for OPC that this is the case under the environmental agency's applicable rules.

Q. Did CP&L, now Progress Energy Carolina ("CPL"), test burn PRB coal in the 1990's?

A. Yes. In February 1997 CP&L hauled PRB coal 2,200 miles by rail. This compares with 1,800 miles to Scherer in Georgia. Moreover, unlike Crystal River Units 4 and 5, CP&L's units were not designed to burn PRB coal.

Q. What was the delivered price in 1997 of PRB coal to CP&L?

A. The delivered price was 179.5 ¢/MMBtu to Mayo (one train).

Q. How did these prices compare to Central Appalachian coal to Crystal River Units 4 and 5 via International Marine Terminal (IMT), the barge loading facility on the Mississippi River owned by PEF's affiliate, in 1997?

A. CP&L's delivered PRB price was about $32.00/ton. PEF's delivered 1997 price for Central Appalachian bituminous coal to Crystal River Units 4 and 5 was made up of $43.44 per ton delivered to IMT and a $8.27/ton Gulf barge charge for a total of $51.71/ton.

Q. And you believe PRB coal could be delivered to Crystal River Units 4 and 5 for less than it was to CP&L?

A. Yes, shipments of PRB coal to TECO in Florida and PRB bids to PEF/PFC show this has consistently been the case. (See Exhibit ___ (RS-10).)

Q. Was PRB coal economical for CP&L?

A. No. CP&L is too close to the CAPP coal fields for PRB to be more economic than CAPP coal, especially in units not designed for PRB coal.

Q. Please comment further on the history of PEF's environmental permits for Crystal River units 4 and 5.

A. After applying for a Title V permit limited to "bituminous" coal in March 1996, PEF engaged in a long dispute with FDEP over whether it could burn very high sulfur petroleum coke in a blend at Crystal River 1/2. At first, FDEP opposed pet coke, but later changed its mind to allow it, but was overruled by U.S. EPA. This dispute was not over until 1999, when PEF withdrew its efforts to add pet coke. However, PEF amended its pending application to request authority to burn "bituminous briquettes", a form of "synthetic fuel" derived from bituminous coal. I will discuss this in more detail later. This request was granted. In 2004, PEF was required to renew its Title V permit. Again, in its application for renewal it did not identify sub-bituminous coal as a potential fuel for Crystal River Units 4 and 5. It is clear, then, that PEF knew and pursued the routine for amending its Title V permit, but chose not to seek to add sub-bituminous coal following its first omission.

Q. Earlier you testified that PEF sought bids from PRB producers in 1995, 1998, 2001, and 2003, in addition to the 2004 RFP. What is the earliest solicitation by PEF for PRB coal that you have examined?

A. While OPC asked for documents related to earlier RFPs, at this point the 2003 RFP process is the earliest RFP process for which I received discovery documents. When PEF/PFC evaluated bids received in July 2003, they showed PRB coal was by a wide margin the least expensive Crystal River Units 4 and 5 coal. Colorado bituminous coal was comparable on a delivered price basis to PRB coal. As evaluated by PFC, PRB coal at $2.02/MMBtu was 33 cents/MMBtu less expensive than Central Appalachian bituminous (CAPP)/synfuels coal and 11 cents/MMBtu less expensive than imported coal. This is not surprising, as such results reflect why utilities had been purchasing PRB coal in large quantities since the early 1990s.

Q. What did PEF do in response to the 2003 results?

A. PEF labeled the PRB bids "FOR TEST PURPOSES ONLY-REVIEW LATER".

Q. That's all?

A. Yes, no test burn was conducted.

Q. Did PEF eventually conduct a PRB test burn?

A. In April 2004, as a result of the March 2004 solicitation and under pressure to reduce water route transportation cost, PEF ordered a quantity of PRB coal for a "test burn".

Q. What happened?

A. While the test was underway, a PEF environmental staffer alerted the plant that PEF's revised Crystal River Units 4 and 5 Title V permit did not allow subbituminous PRB coal to be burned.

Q. So the coal procurement and operational folks did not even realize Crystal River's 4/5 air permit did not allow PRB coal to be burned?

A. It is even worse than that. Some PEF personnel involved did not realize Crystal River Units 4 and 5 were <u>designed</u> to burn a 50% PRB blend.

Q. After the test burn was halted, PFC could not take advantage of the economical PRB bids it had received in March 2004?

A. That is correct. The failure to have and maintain the PRB burn capability was especially crucial in 2004, when prices of Central Appalachian and imported bituminous coal had jumped but PRB prices had not. (See Exhibit ____ (RS-7).)

Q. Did PEF try to obtain a permit revision to burn PRB coal?

A. Yes, but apparently not until after an April 2005 visit by Progress Energy, Inc.'s CEO to subsidiary Progress Fuels Corporation's upriver docks (see PE's chronology at Exhibit ____ (RS-12)). In support of its request for renewed authority to burn PRB coal, PEF acquired an analysis of a PRB/Central Appalachian bituminous blend from affiliate Kanawha River Terminals dated June 23, 2005 and offered it to FDEP in February 2006. PEF studied the issue internally in 2005 in studies by Daniel Donochod, of PE's Strategic Engineering Unit, and beginning in the fall of 2005 in studies by the engineering consulting firm of Sargent and Lundy. These studies showed major fuel savings were possible at Crystal River Units 4 and 5 with PRB blends, minor upgrade costs to update Crystal River coal dust controls, and no major capital cost to burn PRB coal at Crystal River Units 4 and 5 in a 50% blend with Central Appalachian bituminous coal. Significant upgrades were indicated to be necessary in a scenario involving the burning of a blend containing 70% PRB and 30% Illinois Basin coal, but this was not what Crystal River Units 4 and 5 was designed to burn. Relevant supporting documents are at Exhibit ____ (RS-12). PE studies dated April 27, 2006, August 22, 2005, and September 27, 2005 showed fuel savings of $48.9 million; over a period of only several years, assuming only a 20% PRB blend.

<u>Synfuel</u>

Q. Turning to the next subject that you mentioned when addressing PEF's response to developments in the PRB markets, what are synfuels?

A. Synfuels are a tax-defined coal that, as a result of a federal statute, receives a large tax credit through 2007, except when crude oil is above about $65/bbl. A synfuel is generally a coal that has been chemically altered (on the surface) by a plant placed into service prior to July 1, 1998. Various "reagents" are added to obtain this reaction, which does not alter coal's basic characteristics.

Q. What is the value of synfuels tax credits claimed by Progress Energy, Inc. to date?

A. According to <u>Argus Coal Daily</u> (August 10, 2006, p. 3), the total is $1.25 billion..

Q. Did PEF need a permit to burn synfuels at Crystal River Units 4 and 5?

A. Yes. On February 22, 1999 FPC wrote to FDEP as follows: "As you know from previous correspondence, Florida Power Corp. (FPC) has been approached by its fuel supplier, Electric Fuels Corp., concerning the possibility of burning "coal briquettes" at its Crystal River plant." (See letter at Exhibit ____ (RS-13).) In context, it is clear that the briquettes are synfuel.

Q. Was the permit issued?

A. Yes. PEF was permitted at its Crystal River units by FDEP in early 2000 to burn a "bituminous coal briquette mixture" defined as: "coal fines combined under heat and pressure with a small amount of oil to form briquettes" (FDEP, June 29, 1999 Public Notice.

Q. Did the additive used by PEF's affiliates to make "synfuels" add sulfur?

A. Yes, according to PEF's permit filing. To avoid an increase in emissions, synfuels burned by PEF at Crystal River Units 4 and 5 had to have as a raw coal feed a lower sulfur content coal than PFC/EFC previously specified for Crystal River Units 4 and 5. This increased the cost of the raw coal product. (See PEF-FUEL-004750 a 9/2/03 note regarding July 2, 2003 procurement and PEF documents filed with FDEP.)

Q. But didn't synfuel bidders give a discount over the CAPP price in order to take the tax credit?

A. Yes, but this was of no benefit to Florida ratepayers, who, taking into account the price at which PEF purchased synfuel, had less expensive options for coal delivered to Crystal River 4 and 5 through IMT, such as PRB and imports; besides, synfuels purchased from PEF affiliates were more costly than Central Appalachian bituminous coal by rail to Crystal River Units 4 and 5. Moreover, the July 2003 solicitation results suggest in PEF's case Progress Fuels Corporation's conflict of interest as a buyer for PEF and purchaser of synfuel from its affiliates denied even this small discount to PEF's ratepayers.

Q. Please recap your discussion of the permit history.

A. PEF let its PRB permit lapse, and did not seek to rectify its omission, but when a non-regulated affiliate sought tax breaks for Progress Energy, Inc. at the expense of PEF's ratepayers, PEF quickly acquired a synfuels permit. PEF moved quickly to help its affiliate get two breaks for its parent, Progress Energy, but it took from 1993 to 2006 for PEF to prepare to burn the economical PRB coal for which Crystal River Units 4 and 5 were designed. (See Exhibit ____ (RS-13).)

Q. What quantity of synfuel did PEF purchase during the period 2000-2005?

A. These amounts are shown in Exhibits ____ (RS-14) and ____ (RS-15).

Q. Were PEF's ratepayers injured by PEF's purchase of synfuels instead of PRB coal?

A. Yes. During the several years when PEF was buying and burning synfuel, Powder River Basin sub-bituminous coal was available at delivered costs lower than those incurred by PEF to obtain synfuel.

Q. On what do you base that statement?

A. As I will develop in more detail in the following section, PEF reported the actual delivered cost of the synfuel it purchased to the FERC and to the FPSC. I base the statement on a comparison of those actual costs to the costs of the alternatives that were known at the time.

Q. Doesn't PEF deny the synfuels shipments to Crystal River Units 4 and 5 via IMT were purchased from affiliates?

A. No. PEF denies that synfuels <u>purchased</u> from affiliates were <u>*produced*</u> by affiliates. The synfuel was produced by partnerships in which companies owned by Progress Energy, Inc. held ownership positions, which holdings were apparently designed to avoid the categorization of "affiliate." (See Exhibit ____ (RS-16).)

Q. What were the arrangements?

A. PE maintained a complex web of synfuel producing companies with facilities at EFC/PFC docks on the Kanawha (Marmet and Quincy), Upper Ohio (Ceredo), and Big Sandy (Big Sandy) rivers. At Exhibit ____ (14(b)) is PEF's summary of the synfuels "Producing Companies" and "Marketing Agent Companies" that constituted the vendors of synfuels to the Crystal River plant, mostly to Crystal River Units 4 and 5 via IMT.

Q. How were these deliveries reported to FERC and to the FPSC?

A. See Exhibit ____ (RS-14(c)) for example reports.

Q. What were the "agent" sales companies?

A. Black Hawk Synfuels, Sandy River Synfuels LLC, Kanawha River Terminal, Riverside Synfuel, Progress Fuels, and Marmet Synfuel.

Q. What were the synfuel producing companies?

A. New River Synfuel LLC, Sandy River Synfuel LLC, Colla Synfuel, Imperial Synfuel, and RC Synfuel.

Q. What percentage of Central Appalachia bituminous (CAPP)/synfuels deliveries to IMT for Crystal River Units 4 and 5 were PEF "affiliate" shipments?

A. As a percent of CAPP bituminous coal/synfuels delivered to IMT for Crystal River Units 4 and 5, PEF affiliates garnered 53% of these sales in 2000, 88% in 2001, 99% in 2002, 78% in 2003, 75% in 2004, and 36% in 2005. See Exhibit ____ (RS-14).

Q. What was the tax benefit per ton of synfuel?

A. About $27/ton in 2003.

Q. Did PEF affiliates submit winning bids in response to solicitations to ship coal/synfuel to Crystal River Units 4 and 5 via IMT?

A. PEF (and Progress Fuels Corporation) awarded contracts to affiliate synfuel bidders, but synfuel bidders were not the most economical alternatives.

Q. Please explain.

A. First, it is clear that PEF had less expensive options for Crystal River Units 4 and 5 coal than synfuels from Progress Fuels Corporation's docks at Marmet, Quincy Ceredo and Big Sandy. These options were PRB coal; western bituminous coal; imported coal; and Central Appalachian bituminous coal by rail direct to Crystal River Units 4 and 5 (through 2004). PEF/PFC set up the bids and tonnage allocations to carve out most of the water route tons via IMT for its related companies to produce as synfuels and ship via its affiliate river docks and affiliate river and Gulf barges and IMT port system to Crystal River Units 4 and 5. PEF/PFC solicitations excluded the more cost effective options. This was imprudent.

Q. But didn't Progress Fuels Corporation's predecessor entity, EFC, sell its MEMCO barge company and its share of IMT in 2001?

A. Yes, but the sale was with contracts with Progress Fuels Corporation to move this coal that did not expire until 2004, thus enhancing the value of the 2001 sale at the expense of the ratepayer. And the incentive PEF affiliates have to move synfuels from their upriver docks continues to this day. The synfuel tax credit does not expire until the end of 2007 and PEF has a large investment in the up river docks.

Q. Do you have additional observations regarding the manner in which synfuel prevailed in solicitations conducted by PEF and Progress Fuels Corporation?

A. Yes. There is the question of whether, even limiting solicitations to water route, Central Appalachian bituminous/synfuel coal to Crystal River Units 4 and 5, PEF's affiliates won the bids among these limited bidders fairly. My answer is PEF gave its synfuel affiliates special treatment.

Q. On what do you base this statement??

A. First, it is statistically impossible in a market as large as Central Appalachian bituminous coals for a supplier to garner in an open sealed bid market the proportions, which were achieved by PEF affiliates, of the CAPP/synfuels tons to IMT for Crystal River Units 4 and 5.

Q. What do the details of the solicitation process show?

A. They show PEF/PFC segregated bids for Crystal River Units 4 and 5 between water route and rail route bids. Water route bids were further segregated between CAPP/synfuels which were transported and transloaded via affiliates (or ex-affiliates with legacy contracts), and imported coal which usually moved to IMT but occasionally to McDuffie Terminal in Mobile. An example of favoritism occurred in July 2003. Documents obtained from PEF reveal the low bidder, a non synfuel, CAPP coal bidder, offered more coal than PFC wanted to buy, yet PFC did not act promptly to buy the coal. PFC, instead offered to buy from its related company, Black Hawk Fuels, and offered ("Al" Pitcher to "Joe" Jefferson) tons to Black Hawk at a stipulated price which was not the price that Black Hawk had bid. Black Hawk replied it did not have a firm supply of coal! Black Hawk, which had supposedly provided a firm July 2, 2003 bid for 2004 and 2005 coal, then claimed it had located the coal, but at a higher price than it originally had bid. See Exhibits ____ (RS-14(b)) and ____ (RS-14(c)).

Q. Do you have additional concerns?

A. Yes. EFC-PFC had a conflict of interest. PFC was supposedly buying coal for PEF at least cost to the ratepayer. Yet PFC's synfuels plants at its docks needed to purchase the same fuel to generate profits (tax benefits) for its parent Progress Energy

Q. Was this purchasing behavior imprudent? If so, how?

A. From the standpoint of PEF's ratepayers, it was imprudent. First, there was an obvious conflict of interest at PFC. Second, any bid like Black Hawk's not backed by a firm coal supply should be rejected. The lack of a firm supply at the time of bid is a disqualification. (This is different than a bid provided "contingent on prior sale," which is an acceptable practice.) Third, it is highly irregular to have "Al" to "Joe" affiliate negotiations and offers and counter offers that are not formalized and communicated to the other short list bidders, because presumably they had a committed coal supply. Fourth, in this case, since ultimately no July-September transaction was consummated, the ratepayer incurred damages because the coal had to be purchased in 2004 at higher prices. It is even possible, given the structure of PEF's affiliates, that a non-regulated PEF affiliate synfuel plant was the "prior" purchaser of the low July 2003 bid for Central Appalachian coal offered by Infinity Coal Sales/Panther Mining. My proposed adjustments would remedy the cost to the ratepayer of these abuses, but only through 2005.

Q. What was the coal/synfuel/import mix by the water route to Crystal River Units 4 and 5?

A. These data are at Exhibit ____ (RS-15).

Q. What do the data tell us?

A. Up until 2000, most Crystal River 4 and 5 coal delivered via IMT was non-affiliate Central Appalachian bituminous coal moved by PEF's affiliate company, Progress Fuels Corporation ("PFC"). PFC owned and operated a barge/dock network. PFC also owned and operated coal mining companies. PFC-produced coal shipped to IMT for Crystal River Units 4 and 5 was about 25% of receipts. Only after January 1, 2000 were Crystal River Units 4 and 5 permitted to burn affiliate synfuels (but not PRB, because PEF imprudently let its ability to burn PRB coal in Crystal River Units 4 and 5, lapse). After 2000, PFC affiliate synfuels shipments to IMT 4/5 became the dominant source of coal/synfuels and the most expensive source of coal/synfuels to Crystal River Units 4 and 5. See Exhibit ___ (RS-19). This was generally true for 2000-2005. One exception was in 2002, when a very high priced shipment of 111,000 tons of Venezuelan coal arrived at IMT for delivery to Crystal River 4 and 5.

Imports, The 2004 Water "Cap", And Water Route Economics

Q. What was the role of imports? Were they economical relative to Central Appalachian bituminous coal and affiliate synfuels?

A. During the period 1996 to 2005, except for 2002, imports were less expensive than CAPP coal and affiliate coal/synfuels shipped to Crystal River Units 4 and 5 by the water route. See Exhibit ____ (RS-19). But PEF did not shift to imports earlier, as Southern Company did at its Gulf plants. As was the case with PRB coal, when cheaper imported coal was available it usually lost out to bituminous coal and synfuels produced and transported by PEF's affiliated companies.

Q. Did PEF eventually increase imports?

A. Yes. By 2004 PEF increased its reliance on imported coal for Crystal River Units 4 and 5 at IMT from 30% in 2003 to 48% in 2004 and 2005. PEF made economical purchases of imports for 2003 and later years (under earlier contracts), but by August 2003 new import contract and spot prices jumped, making additional purchases very expensive. This development notwithstanding, PEF purchased additional very high-priced imports in

September 2004, see Exhibit ___ (RS-18), probably as part of its strategy to minimize the impact of the water route transportation cap agreed to in April 2004.

Q. What did this "cap" have to do with imported coal?

A. In 2003, PEF and parties negotiated a cap to what PEF could charge ratepayers for waterborne transportation of coal during 2004. Prior to the imposition of the cap, PEF had been billing the ratepayers about \$17.33 per ton (2000-2003) and \$19.61/ton in early 2004 just to get CAPP coal and synfuels to IMT on the Mississippi, then another \$9.39/ton (in 2003) to move coal/synfuels from IMT across the Gulf to Crystal River Units 4 and 5. It was also billing \$5.05/ton to transload imported coal. According to PEF's September 2004 FPSC 423, these rates were changed as a result of the water settlement from \$19.61/ton to \$15.94 or \$10.19/ton; from \$5.05/ton to \$3.74/ton and from \$9.39/ton to \$6.96/ton, respectively. So unless PEF found a way to reduce transportation costs in 2004 it stood to lose money, or at least have its profits fall.

Q. What were PEF's options to reduce water route transport costs?

A. PRB coal was one option, delivered to the Cora, Cahokia or the Cook docks near the confluence of the Ohio and Mississippi Rivers, or to the McDuffie Terminal at Mobile, Alabama. (See Exhibit__(RS- 17.))

Q. Did PEF try this?

A. Yes. As I stated earlier, PEF/PFC solicited PRB coal in April 2004 and began to test burn in April 2004, but the procurement personnel at PFC did not realize PEF had failed to maintain a Crystal River Units 4 and 5 air permit to allow it to burn the PRB coal that Crystal River Units 4 and 5 were designed to burn (on a 50% tonnage basis). This coal was by far the least expensive coal via the water route (see Exhibit ____ (RS-19)) and would have carried much lower transportation cost than Central Appalachian/synfuels coal.

Q. When the PRB burn plan was halted by air permit problems, what did PEF do?

A. PEF had two choices: Central Appalachian coal/synfuels or imported coal. But more CAPP coal would have caused PEF to exceed its water route $/ton transportation cap. So PEF bought imported coal. The imported coal carried a low transportation cost, but the commodity itself was very expensive.

Q. What were the consequences for the ratepayer?

A. On a delivered basis, the coal was very costly—more expensive than alternatives.

Q. How costly?

A. The September 2004 very high priced FOB South America coal purchases of imported coal are shown at Exhibit ____ (RS-18).

Q. Have you provided the actual prices paid by PEF for synfuels and imports for the years 2000-2005 compared these to the PRB prices PEF would have paid had it burned PRB coal at Crystal River Units 4 and 5, purchased via the water route?

A. The results in $/MMBtu are displayed at Exhibit ____ (RS-19).

Q. Summarize what do these results show?

A. They show:

1. PEF synfuels were very costly for ratepayers.
2. Imports were less expensive than affiliate coal/synfuels except for 2002, which contains an unexplained high priced shipment of Venezuelan coal.
3. Available PRB coal would have saved ratepayers millions of dollars in fuel costs (see later section on excessive fuel charges).
4. Central Appalachian coal via the water route was more expensive than Central Appalachian coal via the all rail route.

Q. What were the sources of imports to Crystal River Units 4 and 5 at IMT over 2000-2005?

A. Colombia, Venezuela, Poland, and Russia.

Q. PFC could buy from these countries, but not from Wyoming?

A. Correct.

Q. Please summarize your points regarding PEF's response to developments in the PRB coal markets.

A. In the face of an industry-wide move to cheaper PRB coal, PEF unilaterally surrendered its authority to burn PRB coal. Instead, it purchased demonstrably more expensive bituminous coal and synfuel, unfairly favoring those sources during solicitations in the process. Ratepayers were adversely affected by PEF's behavior.

SECTION V

ECONOMIC FUEL CHOICES FOR CRYSTAL RIVER UNITS 4 AND 5 VIA THE WATER ROUTE

Q. How would the revenues and earnings of PEF's affiliates in the mining and transportation businesses have been affected, 1996-1999, had PRB coal displaced bituminous coal in deliveries to IMT for Crystal River Units 4 and 5?

A. Such shipments would have reduced the affiliates' barge and dock revenues. PRB coal would have reduced the market for PEF's affiliate coal companies, which were losing money in 1995 and 1996. At the end of 1996 Florida Progress Corporation took a $25.2 million charge for a write down of the value of its subsidiary's coal producing assets in Central Appalachia.

Q. If PEF had purchased it at the time, how would PRB coal have moved to Crystal River Units 4 and 5?

A. There are three options. First, PRB coal could move entirely by rail to Crystal River Units 4 and 5 with delivery by CSX and PRB and origination on either the BNSF or UP rail lines. Second, the PRB coal could move to Crystal River Units 4 and 5 by rail to a river dock, then by river barge to New Orleans, then by ocean barge to Crystal River Units 4 and 5. Third, the PRB coal could move by single line BNSF or two line, UP/BNSF or UP to CN (IC) or to NS or CSX to the McDuffie Coal Terminal in Mobile, Alabama, then be transloaded to Gulf barge to Crystal River Units 4 and 5. I have prepared a map at Exhibit ____ (RS-17) that shows the relevant river and Gulf docks.

Q. Which route would have been the most economic?

A. I believe via McDuffie at Mobile would have been the most economic. This is confirmed by bids for "all rail" coal transported to McDuffie Terminal that PEF received on Aug 23, 2002 and May 8, 2003.

Q. Why do you say the bid confirms McDuffie as the most economic route?

A. Because the BNSF would have competed with the UP/ICG for this movement. Moreover, the Alabama State Docks at McDuffie had capacity, could blend, if necessary, and would have been a less expensive Gulf barge haul to Crystal River than from IMT (New Orleans). On May 8, 2003 BNSF and UP bid $15.95/ton for test shipments to McDuffie in railroad-owned cars, having earlier, on Aug 23, 2002, bid $17.91/ton. Usually post-test burn contract rail rates of the same vintage are not higher than the railroad's test burn rates because volumes are higher and the term is longer.

Q. How much would PEF have saved its ratepayers per year from 1996 to 2005 had it used PRB coal instead of bituminous coal via IMT to Crystal River Units 4 and 5?

A. As I show later in my "excess charges" testimony, the savings at a 50% of Crystal River Units 4 and 5 shipment level would have been $5-10 million per year during the period1996-2000, and in excess of $15 million per year during 2001-2003. In 2004 PEF would have reduced the amounts it charged customers through the fuel cost recovery clause by $17 million. In 2005 alone the available savings were almost $22 million. Because the prices of imported coal and CAPP coal surged in 2004 and 2005, but PRB prices did not (see Exhibit__(RS- 7)), PEF's failure to burn PRB coal in 2004 and 2005 led to highly excessive charges to PEF's ratepayers in 2004 and 2005. SO_2 allowance damages were also higher in 2004-2005.

Q. Have you prepared a table comparing the PRB delivered price via IMT (New Orleans) vs. the price of PRB coal delivered via Mobile?

A. Yes, at Exhibit ____ (RS-20).

Q. Why did you calculate excessive fuel charges assuming PRB would have moved via New Orleans if you believe Mobile's Dock would have resulted in lower cost?

A. It came down to the availability of good data. I obtained from FERC reports actual purchase prices of PRB coal delivered to TECO's ECT terminal in New Orleans. I did not have the benefit of actual purchase data from a competing Mobile Gulf barge. Nor was I able to compare an actual purchase with a purchase of PRB coal delivered "all rail" to Mobile with PRB rail to Cook, Cora, or Cahokia, as well as all rail to Crystal River, which PEF/PFC should have done had it been interested in PRB coal. Since, as I stated, the Mobile route would have been the more economical, at least in some years, by using the IMT route in my calculations I have been deliberately conservative in the quantification of excessive fuel charges. Markets change, and a facility with the fuel and transportation flexibility built into PEF's Crystal River assets should respond to such changes. PEF did not respond or use Crystal River's flexibility.

Q. At this stage of your testimony, can you summarize the delivered price of PRB coal to New Orleans docks compared to the cost of the bituminous coal that Progress Fuels Corporation, PEF's coal procurement agent, actually purchased priced to IMT at New Orleans?

A. Yes. Let me start by comparing the delivered price of PRB coal to TECO's Electro-Coal Terminal compared to FPC/EFC's delivered price of Crystal River Units 4 and 5 coal to IMT as reported to FERC. These results are at Exhibit ____ (RS-21).

Q. Are the differences significant?

A. Very significant, especially on two million tons per year. They are equivalent to $7.25 to $20.75 per ton on a 25 MMBtu/ton of bituminous coal heat value basis. However, these 1996-2003 results are subject to a slight Gulf barge Btu adjustment of about 12 to 16 cents/MMBtu and a blending cost at the Crystal River site of 4 cents/MMBtu against the lower Btu/lb PRB coal which must be blended at Crystal River. I make these adjustments in my "overcharges" calculations. These numbers to New Orleans were public FERC data, which should have been a "red flag" to PEF/PFC's personnel, had they acted prudently.

Q. How could they ignore TECO's PRB delivered prices versus their bituminous coal delivered prices to IMT?

A. It is a fundamental imprudency to ignore such market information.

Q. Would these savings have been achievable by any other bituminous coal source?

A. During the period 1996-2003, some of the savings were achievable using either imported South American bituminous coal, Colorado bituminous coal delivered by the water route, or Central Appalachian "CAPP" bituminous coal delivered by rail directly to Crystal River Units 4 and 5. In mid-2003, international coal prices rose, making imported coal more expensive, followed by a "sympathetic" CAPP bituminous coal price jump in August-September 2003. PRB subbituminous coal prices <u>did not rise in 2004 or 2005</u>, making PEF's imprudent actions regarding subbituminous coal even more costly to PEF's ratepayers in 2004 and 2005. (See "Overcharges" section at the end of this testimony and Exhibit ____ (RS-7) for coal price trends.)

Q. Does PRB coal have lower SO_2 emissions than bituminous coal?

A. Yes, much lower.

Q. Would the lower sulfur content of PRB coal have enabled PEF to lower fuel-related costs further?

A. Yes. Due to changes in the Federal Clean Air Act that affected Crystal River Units 4 and 5 on January 1, 2000, PEF was assigned "allowances" of SO2. If PEF had burned PRB coal, it would have reduced its consumption of SO2 allowances. The additional savings, which I calculate later, are $1-2 million per year 2000-2003, $4.2 million in 2004, and rise to $7.5 million in 2005.

Q. Was PEF aware of the opportunity to capture such savings?

A. Yes. Documents provided to OPC during discovery show that PEF recognized the impact of PRB coal's low sulfur content on the cost of allowances as a positive factor in its evaluation of bids.

Q. Is there a document that summarizes the situation at Crystal River Units 4 and 5 regarding utilization of PRB/Central Appalachian blends?

A. Yes. At Exhibit ____ (RS-22) are the meeting minutes of a September 27, 2005 meeting at Crystal River Units 4 and 5 which reviewed the upgrades required to burn PRB CAPP blends.

Q. What was the conclusion?

A. The furnace, convection passes, ESP's and pulverizers were designed for a 50% PRB blend. While some upgrades were required, they did not involve major capital investments. Further, NOx and SO2 emissions would drop, and O&M costs would increase in some areas but decrease in others.

Q. What about FDEP?

A. In February 2006 PEF met with FDEP and in May 2006 a PRB test burn was successfully conducted.

Q. What was the result of the PRB test burn?

A. As reported to FDEP on July 20, 2006 at a 30%/70% PRB/CAPP blend ratio:

> "There were no substantial issues raised during this trial. Full load was achieved and LOI (loss of ignition) was as good as or better than the base line coal performance measurements. Major emissions constituents, such as NO2, SO2, and opacity, were equivalent to or better than the same constituents utilizing the base line coal.
>
> In addition to the major emissions constituents discussed above, detailed stack testing of CO2 PM and ash resistivity testing were required to meet the Florida Department of Environment Protection (FDEP) requirements. Particulate Matter was basically unaffected by the PRB blend as compared to baseline. CO, which is not currently regulated, was reportedly low during the baseline tests. CO readings did register while burning the PRB blend."

Q. Your conclusions?

A. It cannot be surprising that Crystal River 5, designed to burn 50/50 PRB/CAPP coal, was successful burning a 30/70% PRB blend. What this test did show was that the April 2004 test was mismanaged by PEF. In 2004 the Crystal River soot blowers, electrostatic precipitators (crucial to controlling dust), and some coal handling equipment had not been maintained, preparations for the test were inadequate, and plant personnel at Crystal River Units 4 and 5 had not been prepared or briefed adequately.

Q. Is this typical for utilities?

A. No. I am very familiar with the circumstances of introducing PRB coal to units previously burning other coals. It is not surprising that with hundreds of millions of tons of PRB coal being burned, knowledge of how to burn it is not scarce. In fact, for many years a "PRB Users Group" has existed which meets annually, technical papers are available, and the major engineering consulting companies and boiler manufacturers have significant experience in introducing PRB coals into units that have not previously burned them. Sargent and Lundy, PEF's consultant, was involved in the introduction of PRB coal into TVA's power plants in the mid-1990's, and TVA's units were <u>not</u> designed to burn PRB coal.

Q. Was FDEP supportive of PEF's proposal to conduct a test burn of PRB coal?

A. Yes. When FDEP issued its public notice on the Crystal River 5 test burn permit on April 4, 2006 it cited a 2003 article "Burning PRB Coal" in <u>Power Magazine</u> on which it relied in informing the public of the benefits of using PRB coal. The chief benefit that the FDEP cited in its technical evaluation was the ability to lower fuel costs. See my Exhibit ____ (RS-23).

Q. Could this May 2006 test burn have been conducted in 1995-1996?

A. Yes. Many utilities test burned PRB coal from 1989 to 1997. PEF could have done it too. In fact, bearing in mind that the 50/50 PRB/bituminous blend is the design basis coal for the units, it is surprising to me that PEF did not test the blend at the outset of operations in the early 1980s.

Transportation Risks

Q. Are there transportation risks to moving PRB coal?

A. No more than for any other long haul coal transportation movement. The PRB haul from mine to IMT is 2,209 miles versus 1,703 miles for the CAPP coal from West Virginia mines via PFC's Marmet dock.

Moving PRB coal by rail in 200,000,000 to 400,000,000 tons per year quantities has occurred for 20 years. There were railroad disruptions in 1997-1998 and the last half of 2005, but these were no more severe than water route disruptions on the Ohio and Mississippi Rivers and across the Gulf due to droughts, floods, and hurricanes. Those water route disruptions affect Central Appalachian bituminous coal, too.

Q. What is the mileage comparison via McDuffie at Mobile?

A. An all-rail PRB movement to McDuffie is 1,692 miles, and McDuffie is closer in Gulf barge miles to Crystal River than IMT. Therefore, coal from the PRB was a shorter haul to Crystal River Units 4 and 5 than the Central Appalachia coal/synfuels that PEF's affiliate PFC was shipping from Kanawha River docks to Crystal River Units 4 and 5.

Q. But disruptions occur in the transportation of both PRB and Eastern bituminous coals?

A. Yes. That is why utilities maintain and bill ratepayers for coal inventories. Transportation disruptions, either on rail or on water routes, have not been nearly as severe as the UMWA strike disruptions that routinely occurred in the eastern coal fields up until 1993.

Q. When PEF/PFC received PRB bids in 2003 and 2004, did PEF need to make the railroad arrangements?

A. That was optional for PEF. PEF/PFC received bids FOB dock from qualified bidders that had arranged for the coal supply in Wyoming, had the train sets to move the PRB coal 1,240 miles to the docks in southern Illinois, and had contracted for the dock space to transload coal to river barges.

Q. Did PEF/PFC receive bids for rail transportation alone?

A. Yes. In 2004 bids for rail rate and dock rates including rail cars were received. Therefore, PEF could have purchased coal FOB mine and coupled this purchase with a rail services purchase, or purchased coal FOB with rail-to-dock services from a single vendor.

<u>PRB Bids To Crystal River In 2003 And 2004</u>

Q. What did the PRB coal bids that PEF received in July 2003 reveal about the economics of PRB coal vs. Central Appalachian coal, imports and synfuels, delivered to Crystal River Units 4 and 5?

A. Multiple PRB bids for 2004 and 2005 coal were offered that could have been delivered to Crystal River Units 4 and 5 at $1.99 to $2.00/MMBTU. Western bituminous Colorado coal was offered at the same delivered price. PRB-capable units like Crystal River Units 4 and 5 usually over the long run find PRB coal less expensive than Colorado bituminous coal. However, for the non sub-bituminous portion of the 50/50 Crystal River Units 4 and 5 blend, Colorado bituminous coal could be competitive with Central Appalachian coal via the water route.

Q. According to the July 2003 bids, what was the delivered price of non-affiliate Central Appalachian bituminous coal to Crystal River Units 4 and 5 via IMT?

A. $2.39/MMBTU.

Q. And PFC affiliate coal?

A. $2.42/MMBTU, but as I testified earlier, PFC synfuels had no committed supply to bid.

Q. And imported coal?

A. $2.02/MMBTU via McDuffie was the lowest bid. Bids via IMT were 2.13/MMBTU.

Q. So, delivered via IMT PRB was the least expensive?

A. Yes.

Q. Did PEF/PFC consider PRB bids via McDuffie?

A. No, even though PEF had rail bids from UP/BNSF to McDuffie.

Q. So what did PEF/PFC do?

A. PEF ignored the low PRB bids, and bought higher priced coal.

Q. What did the bids received in April 2004 for 2005 and 2006 coal reveal?

A. PRB coal was the low bid by an even wider margin. See Exhibit ____ (RS-24). CAPP and world (imported) coal prices had increased, but PRB prices had not. PRB coal offered huge savings to ratepayers.

<u>**PEF/PFC's September 2004 Exclusive Award To An Affiliate**</u>

Q. Did PEF/PFC conduct another solicitation in September 2004?

A. No. PFC's Mr. Pitcher contacted three vendors: two foreign producers and his affiliate for Central Appalachian bituminous coal/synfuels.

Q. Was PRB coal solicited?

A. No.

Q. Was water route Central Appalachian coal or synfuels solicited from any non-affiliate?

A. No.

Q. How many tons were purchased from PEF's affiliate?

A. 40,000 tons per month over 2005 and 2006, or 480,000 per year for two years..

Q. Why do you believe this award was imprudent?

A. As I stated in a November 2005 affidavit:

- PEF did not conduct a solicitation or contact any other CAPP/synfuels bidder, despite its lengthy CAPP coal bid list.

- PEF effectively sole sourced a 480,000 ton/year, two year purchase of barge coal on the Kanawha River to an affiliate.
- PEF used published trade press prices to justify the price which data are no substitute for a solicitation and bids.
- At the same time PEF/PFC also purchased from its affiliate 210,000 tons of rail origin coal for Crystal River 1/2 to be delivered over seven months.

Q. Was the 480,000 tons of affiliate barge coal actually delivered in 2005?

A. No. Only 321,100 tons of affiliate coal was delivered.

Q. What is your response to PEF's claim that it did not want to do a solicitation for fear of "spooking" the market?

A. This claim is no excuse for not contacting <u>any other</u> U.S. domestic coal supplier. Further, according to the trade press of August and September 2004, PEF was in the market. See Exhibit ____ (RS-25). So the market was already "spooked". Mr. Pitcher's actions were imprudent.

Q. What coal should PEF have procured in September 2004 as opposed to its affiliate's CAPP coal?

A. PRB coal was the only coal available in September 2004 that had not risen in price.

Q. Do your calculations of excessive charges provide the ratepayer relief from this imprudent purchase?

A. Yes.

SECTION VI

CALCULATION OF EXCESSIVE FUEL CHARGES AND CONCLUSIONS

Q. Did you calculate the excess costs billed to PEF's ratepayers from 1996 through 2005 due to PEF's imprudent actions regarding purchases of water route coal, its failure to maintain its authority to burn PRB coal at Crystal River Units 4 and 5, and its failure to use PRB coal in Crystal River Units 4 and 5 when market conditions warranted its use?

A. Yes. These costs are of two types: excess fuel cost and excess SO_2 allowance cost. They are summarized in Exhibit ____ (RS-26). The excess charges total $134.5 million, representing $116.6 million for excessive coal costs and $17.9 million for excess SO2 allowance costs.

Q. Please describe the methodology you used to arrive at the $134.5 million figure.

A. My analysis compares the costs that PEF actually incurred during the period by purchasing bituminous coal and synfuel with the lower costs that, based on information that PEF knew or should have known at the time, PEF should have realized for its ratepayers.

Q. How did you calculate the actual costs that PEF incurred?

A. The actual costs, including the costs of transportation, are reported to the FERC and to this Commission monthly on Form 423.

Q. How did you calculate the costs at which PEF could have purchased the more economical alternative during 1996-2005?

A. During much of this period, TECO purchased PRB coal and transported it first to the dock on the Mississippi that TECO's affiliate owns, then to TECO's Gannon station. Again, this actual purchase information was available to me for years 1996-2002 from the Form 423 that TECO files with the FERC and the FPSC on a monthly basis. The price that TECO actually paid for PRB during those years makes an excellent and accurate proxy for the price at which PRB coal was available to PEF during the same time frame. Additionally, the cost of transportation to New Orleans incurred by TECO to move PRB coal to ECT represents the cost that PEF would have incurred to move the coal that far. It remained only to calculate the differential cost that PEF would have incurred to transport the PRB coal from New Orleans to Crystal River vs. the cost of moving bituminous coal across the Gulf.

Q. For years following 2002, what did you use as the basis for the cost of PRB coal to PEF?

A. In 2003 and 2004 PEF issued Requests for Proposals, to which producers of PRB responded. I used actual bids by PRB producers to PEF as the source of the price at which PEF could have purchased PRB coal in 2004, and 2005.

Q. What quantities of PRB coal did you assume?

A. I assumed that, after an initial ramp-up phase, a prudent PEF would have burned the "design basis" 50/50 blend of sub-bituminous and bituminous coals during the period in question.

Q. Why did you assume the 50/50 "design basis" blend?

A. The designers of Units 4 and 5 guaranteed that the units would operate as specified when burning the design basis coal. Accordingly, by using the design basis coal I mooted any issue or contention that my assumptions would have caused operational problems or deratings at the plant site, or that they would have required significant additional investment. Since several utilities successfully burned more than 50% PRB coal, I think the 50/50 assumption is conservative.

Q. You mentioned that you assumed a "ramp-up" phase. Please elaborate.

A. I assumed that in the first year of shifting PEF could have burned about 25% PRB coal, and that it would have reached the 50% level during the second year. In my experience, I think this would have been a reasonable expectation.

Q. Did you make any other adjustments?

A. Yes. Earlier I mentioned that there were transportation disruptions in the last half of 2005. While I believe these would have been fully mitigated with a prudent inventory strategy, to be deliberately conservative I assumed in 2005 PEF would have replaced 7.5% of PRB coal with more expensive bituminous coal, corresponding to a 15% shortfall due to the western railroad's last half of 2005 partial force majeure.

Q. Have you provided an exhibit that explains your calculations in more detail?

A. Yes. See Exhibit ____ (RS-26).

Q. Can you provide an overview of your imprudency and "overcharges" claims?

A. Yes. I believe it is helpful to regard the imprudent actions and resulting overcharges as occurring during three "subperiods." In 2004 and 2005 bituminous coal prices surged, as did SO_2 allowances prices. PEF's failure to burn subbituminous PRB coal, despite the firm qualified bids it had received, was very costly to PEF's ratepayers. This failure was due to PEF's imprudent failures to be prepared to burn PRB coal and to conflicts of interest with affiliate companies that profited from the high priced bituminous coal and synfuels that were paid for by ratepayers. In 2004 and 2005 alone these damages were $50,886,618.

Q. What about the years 2000-2003?

A. During these "synfuels years", PFC affiliates profited from high-priced coal and synfuel sales to PEF under an air permit issued in early 2000 that should have, had PFC acted prudently, allowed PRB coal to be burned. These actions over 2000 to 2003 cost the ratepayers $60,847,549.

Q. And prior to 2000?

A. The failure of PEF to test burn, for operational proving, and burn PRB coal under the air permits issued to Crystal River Units 4 and 5 that contemplated a PRB burn in a 50%

CAPP/PRB blend stands in stark contrast to the actions of other southeast utilities who responded prudently to the favorable economics of PRB coal, from 1993 forward. Again, PEF instead favored its affiliate dock, barge, and coal producing companies at the expense of ratepayers. The cost to the ratepayers of these imprudencies for the years 1996 to 1999 was $22,789,176.

Q. What is the total amount of overcharges stemming from these imprudencies?

A. The total is $134.5 million, before the addition of an appropriate interest factor.

Q. Do you have additional observations?

A. Yes. Of necessity, my analysis addresses a specific time frame. While my recommended adjustments will prevent customers from bearing excessive Crystal River 4 and 5 fuel costs incurred during 1996-2005, I have seen indications that the same type of procurement activity by PEF will impact customers adversely in 2006 as well. I encourage the Commission to continue to monitor such transactions and make additional adjustments where warranted.

Q. Does that conclude your direct testimony?

A. Yes.

DOCKET NO. 060658-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of foregoing Testimony and Exhibits of Robert L. Sansom has been furnished by U.S. Mail on this 3rd day of November, 2006, to the following:

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SANSOM EXHIBIT LIST

1. Robert L. Sansom Resume.
2. Babcock & Wilcox and Black & Veatch Design Documents.
3. FPC Site Certification Documents.
4. FPC Coal Documents 1980 Site Certificate Application.
5. PRB Development.
6. EPRI & DOE PRB Studies.
7. Coal Prices.
8. Map of 1996 PRB Shipments.
9. PRB Shipments to Southeast Plants.
10. Delivered PRB coal costs.
11. <u>Coal Week</u> September 23, 1996 re Miller plant.
12. 2005-2006 Progress Energy PRB Crystal River Units 4 and 5 studies.
13. FPC Briquettes letters and related permits. (p. 23)
14. Synfuels to IMT for Crystal River Units 4 and 5.
    a. Summary Table
    b. PEF Synfuels Summary
    c. FPSC and FERC 423's
15. Crystal River Units 4 and 5 Sources to IMT: 1997-2005.
16. Synfuels documents Progress Energy's U-9C-3 dated 9/30/01. (p. 26)
17. Dock Map.
18. September 2004 High Priced Import Purchases.
19. $/MMBTtu of Different Coals to Crystal River Units 4 and 5 via IMT Water Route and All Rail.

20. Delivered Crystal River Units 4 and 5 Prices via McDuffie vs. via IMT.

21. PRB Coal Compared With Bituminous Coal/Synfuels to New Orleans.

22. PRB Meeting at Crystal River Units 4 and 5.

23. FDEP Excerpts From Power Magazine.

24. 2004 Bids Delivered to Crystal River Units 4 and 5.

25. Trade press on PEF's coal solicitations.

26. "Overcharges" to PEF Ratepayers: 1996-2005.

27. Overcharges Methodology.

28. 1976 "Bituminous" Coal Permit Application to FDEP.

29. PEF's Failure to Seek a Title V Permit to Continue Crystal River Units 4 and 5's Environmental Authority to Burn Sub-Bituminous Coal

Frequently Used Abbreviations

EFC	Electric Fuels Corporation
PFC	Progress Energy Corporation
PE	Progress Energy
PEF	Progress Energy Florida
PEC	Progress Energy Carolinas
CR	Crystal River
CR 4/5	Crystal River 4/5
CAPP	Central Appalachia
PRB	Powder River Basin
FDEP	Florida Department of Environmental Protection
IMT	International Marine Terminals at New Orleans
ECT	Electro-Coal Terminal, later TECO Bulk Terminal
BNSF	Burlington Northern Santa Fe Railroad
UP	Union Pacific Railroad
NS	Norfolk Southern Railroad

Exhibit ____ (RS-1)

Resume of Robert L. Sansom

EXPERIENCE OF

DR. ROBERT L. SANSOM

Education

- ✯ Robert Sansom graduated (B.S.) from U.S. Air Force Academy in 1964.
- ✯ In 1965, Dr. Sansom received a Masters degree in economics from Georgetown University.
- ✯ In 1968/69, he received a B. Phil and D. Phil in economics from Oxford University.

Honors

- ✯ Dr. Sansom was a Fulbright Scholar, Rhodes Scholar, and White House Fellow.

Experience

- ✯ From 1968 to 1969, Dr. Sansom was a White House Fellow assigned to Assistant to the President for National Security Affairs.
- ✯ From 1969 to 1971, he was on Dr. Henry Kissinger's National Security Council staff.
- ✯ From 1971 to 1972, he was Deputy Assistant Administrator for Planning and Evaluation for the Environmental Protection Agency.
- ✯ From 1972 to 1974, he was Assistant Administrator for Air and Water Programs at the Environmental Protection Agency.
- ✯ From 1974 to 1980, Dr. Sansom was President of Energy and Environmental Analysis, Inc.
- ✯ From 1981 to the Present, Dr. Sansom has been President of Energy Ventures Analysis, Inc.

Sansom has been active in energy and environmental consulting since 1974 and throughout the period has focused on the coal, natural gas and electric utilities industries and on related environmental issues.

- ✯ coal, gas, and oil production, markets and prices,
- ✯ coal and gas contracts and procurement,
- ✯ coal suitability and the environmental effects of coal combustion,
- ✯ electric power markets and projects, and
- ✯ coal transportation.

Electric Power Markets

Dr. Sansom analyzes and testifies on electric power markets and prices. In several cases (PEPCO, PP&L, NIPSCO, Entergy, Sierra Pacific, AEPCO, Bonneville Power Administration, for example), Sansom has examined power pricing and power transactions. EVA's analysis employs public and proprietary data and models at the NERC or NERC subregion level and develops forward pricing curves. Sansom presented testimony before FERC in 1996 on Order 888A: promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services.

Coal Markets and Coal Property Transactions

Coal market studies by EVA's coal group cover all the major coal producing and using regions of the United States. Clients include the major U.S. coal companies, major U.S. utilities, and groups such as EPRI and the National Mining Association.

EVA maintains large data bases on all U.S. mines and utility coal users. For clients it utilizes its proprietary coal production cost models and tracks and forecasts demand and prices for U.S. and international steam and metallurgical coals.

The U.S. coal market is regionalized with the reach of a particular coal mine limited by its transportation costs to various markets, its competition as well as the quality of its coal and its production cost. EVA addresses these issues in its market studies on a regional and international basis with analyses sold to clients on a job-specific basis or through its COALCAST subscription coal service.

In coal property and coal company valuations for buyers and sellers, EVA employs its market, cost of mining, and coal contract expertise using discounted cash flow and comparable transactions methods.

Coal and Transportation Contracts

Major U.S. coal transactions occur pursuant to coal and rail transportation contracts between buyers and sellers. Sansom has reviewed over 300 long-term coal contracts and many coal transportation contracts. He has advised utilities and coal companies on coal and rail transportation contract terms and conditions. His expertise is frequently sought and utilized in contract disputes.

Electric Utility Audits

EVA is often hired by Public Utility Commissions to conduct prudency audits of utility coal procurement practices and wholesale power transactions. Sansom has participated in such utility audits in Ohio, Delaware, Florida, Utah, Wyoming, California, Oregon, and Washington, and before FERC.

Natural Gas And Oil Markets

Dr. Sansom has been engaged in analysis of natural gas markets, including mid-stream processing and NGL fractionation. He has examined U.S. and Canadian natural gas production. Other work has addressed world oil markets and OPEC's role therein. Dr. Sansom has examined the role of natural gas combined cycle and coal gasification technologies as base load generating capacity.

Coal Suitability and the Environmental Effects of Coal Use

Sansom's original involvement in the coal industry was in response to the adverse environmental effects of coal use. He has been active in studies on sulfur dioxide, nitrous oxides, particulates, air toxins, and CO_2 emissions. EVA has estimated the cost of specific environmental control technologies at plant sites and the cost of national environmental programs for clients such as the U.S. Environmental Protection Agency, EPRI, and the Department of Energy. It has advised electric utilities on how to comply with acid rain and legislation. Coal suitability involves how a particular coal burns in a particular boiler and how that coal's emissions are treated before discharge to the atmosphere. EVA's studies have included examination of the performance of most U.S. coals used in a broad range of U.S. combustors, including pulverized coal, cyclone, and CFB furnaces.

International Coal and Utility Experience

Sansom has been active in international coal since the mid-1970's, analyzing overseas coal markets and inter-fuel competition. In 1989 Sansom testified in an international arbitration involving a large Canadian coal producer and the Japanese steel industry. Sansom has testified in international arbitrations involving independent power projects in the Philippines and Turkey.

Western Coal, Utility, and Transportation Experience

EVA has broad experience in the western U.S. Sansom's western coal and coal transportation expertise is the basis for his testimony on the Powder River Basin, the fastest growing producing region in the United States.

Expert Testimony

Sansom's expert testimony most often addresses coal contracts, coal markets, coal transportation and the prudency of coal procurements. Since 1998, Sansom has testified in the following court and arbitration cases:

	On Behalf of	Other Party	Year	Court or Regulatory Body
A	CMS Energy	Luzon Power	1998	Hong Kong, China
A	Otter Tail Power/Minnkota Pwr Coop/NW Pub Svc	Knife River Coal Company	1998	Chicago, IL
C	Cedar Bay Generating	Florida Power & Light	1999	State Court Florida
A	Seminole Electric Coop, Inc.	Mt. Vernon Transfer Terminal	2000	Washington, D.C.
A	CMS Energy	Adams Affiliates, Inc. & Cottonwood Partnership	2001	Chicago, IL
A	Government of Turkey	PSE&G	2003-2006	Washington, D.C.
C	Peabody Coal Company/ Indianapolis P&L	John Wasson	2004	U.S. District Court Southern Indiana
PSC	Peabody Western Coal Co.	Mohave/So Cal Edison	2004	California PSC
PSC	CSX	Tampa Electric Co	2004	Florida PSC
A	Marysville Fractionation Partnership	Kinetic Resources	2005	Detroit, MI
A	Dearborn Industrial Generation	Duke/Flour Daniel	2005	Detroit, MI

A Arbitration
C Court
PSC Public Service Commission

Arbitration

Sansom has served as an Arbitrator in three coal contract disputes between utilities and coal suppliers.

Publications

"Gas Turbine Mania: The Merchant Power Plant Shakeout", Public Utilities Fortnightly, June 15, 2002.

"Looking Past California: The Emerging Shape of the Generation Sector", Public Utilities Fortnightly, June 1, 2001, pp. 44-50.

"Refinery Permit Delays Evaluated", Oil and Gas Journal, April 23, 1979, pp. 78-82.

Exhibit ____ (RS-2)

Babcock & Wilcox and Black & Veatch

Design Documents

Instructions

for the

Care and Operation

of

Babcock & Wilcox Equipment

furnished on Contract

RB-588

for

Florida Power Corporation

Crystal River Plant
Unit 4

UNIT DESCRIPTION

PLANT

This unit is installed as Unit No. 4 at the Crystal River Plant located near Crystal River, Florida. Plant elevation is 11 feet above sea level.

The unit supplies steam to a GE turbine rated at 665 MW. The consulting engineer is Black & Veatch, Kansas City, Missouri.

BOILER

This is a semi-indoor, balanced draft Carolina Type Radiant Boiler designed for pulverized coal firing. The unit has 54 Dual-Register burners arranged in three rows of nine burners each on both the front and rear walls. Furnace dimensions are 79 feet wide, 57 feet deep, and 201 feet from the centerline of the lower wall headers to the drum centerline. The steam drum is 72 inches ID.

The maximum continuous rating is 5,239,600 lb/hr of main steam flow at 2640 psig and 1005° F at the superheater outlet with a reheat flow of 4,344,700 lb/hr at 493 psig and 1005° F with a normal feedwater temperature of 546° F. This is a 5% overpressure condition. The full load rating is 4,737,900 lb/hr of main steam flow at 2500 psig and 1005° F with a reheat flow of 3,959,800 lb/hr at 449 psig and 1005° F with a normal feedwater temperature of 535° F. Main steam and reheat steam temperatures are controlled to 1005° F from MCR load down to half load (2,368,900 lb/hr) by a combination of gas recirculation and spray attemperation.

The unit is designed for cycling service and is provided with a full boiler by-pass system. The unit can be operated with either constant or variable turbine throttle pressure from 63% of full load on down.

The design pressures of the boiler, economizer, and reheater are 2975, 3050, and 750 psig respectively.

Steam for boiler soot blowing is taken off the primary superheater outlet header. Steam for air heater soot blowing is taken off the secondary superheater outlet.

SCOPE OF SUPPLY

The major items of equipment supplied by B&W include:

- RBC unit pressure parts including boiler, primary and secondary superheater, economizer, and reheater.
- Fifty-four Dual-Register burners and lighters.
- Six MPS-89GR pulverizers and piping to burners.
- By-pass system including valves and piping.
- Two stages of superheat attemperators (first stage tandem) and one stage of reheat attemperation (2 nozzles); nozzles only, no block or control valves or spray water piping.
- Three Rothemuhle air heaters (one primary and two secondary).
- Ducts from secondary air heaters to windbox.

- Primary air system: two TLT centrifugal PA fans and ducts from fans to pulverizers.
- Gas recirculation system: one TLT centrifugal GR fan, one dust collector and flues.
- Six Stock gravimetric coal feeders and drives.
- Bailey burner controls.
- Safety valves and ERV.
- Brickwork, refractory, insulation and lagging (BRIL).
- Seal air piping and fans.
- Erection.
- Recommended spare parts.

FUEL

The guarantees for this unit are based on firing a 50/50 blend of Eastern bituminous and Western sub-bituminous coal. The performance coal is classified as high slagging and medium fouling. Performance was also checked on Illinois deep-mined coal which is classified as severe slagging and high fouling. The furnace and convection pass are designed for a severe slagging and severe fouling coal.

Ultimate Analysis: % by Weight

	Performance	Illinois
Ash	7.90	13.00
Sulfur	0.49	4.20
Hydrogen	3.90	4.40
Carbon	58.80	62.00
Chlorine	0.03	0.02
Water	18.50	10.00
Nitrogen	1.10	1.38
Oxygen	9.28	5.00
Total	100.00	100.00
Higher Heating Value	10285 Btu/lb	11000 Btu/lb

UTILITY BOILER PERFORMANCE SUMMARY

BY RLG APPD. [illegible] DATE

THE BABCOCK & WILCOX COMPANY

P12-4657-16Y0-1B0

THIS SUMMARY SHEET IS THE PROPERTY OF THE BABCOCK & WILCOX COMPANY AND IS TO BE RETURNED UPON REQUEST. ... FOR FURNISHING INFORMATION TO OTHERS, OR FOR ANY OTHER PURPOSE DETRIMENTAL TO THE INTERESTS OF THE BABCOCK & WILCOX COMPANY ...

FUEL AS FIRED

SAMPLES	
ANALYSES	
50/50 BLEND, EASTERN & WESTERN	
KIND	
CLASS	
GROUP	
MINE	
SEAM	
DISTRICT	
COUNTY	
STATE	
SIZE	
GRINDABILITY	48
SURFACE MOISTURE, %	
	PERF.
ASH SOFT. TEMP., F (REDUCING)	
PROXIMATE – MOISTURE, TOTAL	18.5
VOLATILE MATTER	31.0
FIXED CARBON	42.6
ASH	7.9
TOTAL	100.0

ULTIMATE ANALYSIS – FUEL	BIT.	SUB-BIT.	
% BY WT.	WT.	WT.	WT.
ASH	10.0	5.8	7.90
S	0.5	0.48	0.49
H_2	4.4	3.4	3.90
C	69.0	48.5	58.80
CH_4			
C_2H_4			
C_2H_6			
C_3H_8			
C_4H_{10}			
C_5H_{12}			
C_6H_{14}			
CO			
CO_2			
Cl	0.05	0.02	0.03
H_2O	7.0	30.0	18.50
N_2	1.4	0.7	1.10
O_2	7.65	11.1	9.28
TOTAL	100.00	100.00	100.00
BTU/LB	12,450	8,125	10,285
BTU/CU FT 60F 30 IN.HG			

*EXCLUDING VALVES AND STATIC HEAD.

PREDICTED PERFORMANCE

2	STEAM LEAVING SH, M LB/HR	2368.9	4737.9	5239.6
3	STEAM LEAVING RH¹, M LB/HR	2063.8	3959.8	4344.7
4	STEAM LEAVING RH², M LB/HR			
5	TYPE OF FUEL	PC	PC	PC
6	LOAD CONDITION	CONT.	CONT.	CONT.
7	EXCESS AIR LEAVING ECON., %	35	20	20
8	NO. OF BURNERS IN OPERATION	45	54	54
9	FUEL INPUT, MKB/HR	3348	6053	6581
10	HEAT AVAIL. MKB/HR (FUEL & HEATED AIR)	3615	6367	6886
11				
12	QUANTITY, M LB/HR – FUEL (MCFH-NAT. GAS)	325.5	588.6	639.8
13	FLUE GAS ENTERING AIR HEATER	3728	6051	6579
14	AIR TO BURNING EQUIPMENT	3327	5419	5891
15	AIR HEATER LEAKAGE PRI/SEC	107/210	128/272	131/286
16				
17	PRESSURE, PSIG – STEAM AT SH OUTLET	2425	2500	2640
18	STEAM AT RH¹ INLET	240	474	520
19	STEAM AT RH² INLET			
20	PRESSURE DROP – REHEATER 1	13	25	27
21	REHEATER 2			
22	ECONOMIZER *	5	20	25
23	DRUM TO SH OUTLET	39	155	189
24	TEMPERATURE, F – STEAM – LEAVING SUPERHEATER	1005	1005	1005
25	LEAVING REHEATER 1	1005	1005	1005
26	ENTERING REHEATER 1	528	598	604
27	LEAVING REHEATER 2			
28	ENTERING REHEATER 2			
29	FLUE GAS – LEAVING ECONOMIZER	630	689	697
30	LEAVING AH (EXCL. LKG) PRI/SEC	280/260	280/278	280/279
31	LEAVING AH (INCL. LKG) PRI/SEC	258/249	261/267	262/269
32	WATER ENTERING ECONOMIZER	459	535	546
33	AIR – ENTERING UNIT PRI/SEC	85/99	95/82	95/80
34	LEAVING AIR HEATER PRI/SEC	555/555	575/596	579/601
35	RESISTANCE, IN. OF WATER – GAS – FURNACE & CONVECTION BANKS	1.3	3.5	3.9
36	FLUES TO AH OUTLET	0.4	0.9	1.1
37	AIR HEATER	1.7	3.6	4.1
38				
39	TOTAL FURN. TO AH OUTLET	3.8	8.0	9.1
40	AIR – FUEL BURNERS & WINDBOX	1.0	2.5	2.9
41	DUCTS & FLOW METER	1.2	3.3	3.8
42	AIR HEATER	1.7	4.0	4.6
43				
44				
45	TOT. FROM AH INLET TO FURN	3.9	9.8	11.3
46	HEAT LOSS, % – DRY GAS	4.23	4.34	4.43
47	H_2 & H_2O IN FUEL	5.80	5.89	5.91
48	MOISTURE IN AIR	0.11	0.11	0.11
49	UNBURNED COMBUSTIBLE	0.30	0.30	0.30
50	RADIATION	0.31	0.17	0.15
51	UNACC. FOR & MFRS. MARGIN	1.50	1.50	1.50
52				
53	TOTAL HEAT LOSS	12.25	12.31	12.40
54	EFFICIENCY OF UNIT, %	87.75	87.69	87.60
55				
56	PULVERIZERS – NO. IN USE PER BOILER	5	6	5 / 6
57	TOTAL POWER, KW HR/TON MOTOR OUTPUT			
58	% THRU 200 U.S.S. SIEVE	74	69	65 / 68

59 PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR,

60 ON 29.92 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET &

61 ON ARRANGEMENT SHOWN ON DRAWING P12-4657-16Y0

EQUIPMENT PER UNIT

2	TYPE	RADIANT
3	SIZE	RBC 57 79/HB
4		
5	DESIGN PRESSURE – 2,975 PSIG	
6		
7	FURNACE, SQ FT – WATER COOLED SCREEN (CIRCUMFERENTIAL)	
8	WATER COOLED (PROJECTED)	48,736
9	SUPERHEATER (CIRCUMFERENTIAL)	
10	SUPERHEATER (PROJECTED)	46,442
11		
12	TOTAL FURNACE HEATING SURFACE	95,178
13	CONVECTION – SATURATED (CIRCUMFERENTIAL)	10,586
14	SUPERHEATER (CIRCUMFERENTIAL)	243,015
15	REHEATER 1 (CIRCUMFERENTIAL)	331,919
16	REHEATER 2 (CIRCUMFERENTIAL)	
17	ECONOMIZER	46,519
18	TOTAL CONVECTION HEATING SURFACE	634,039
19	TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	729,217
20	FLAT PROJECTED FURNACE HEATING SURFACE	
21	TO FACE OF PLATENS (24" CTR)	73,581
22	TO FACE OF CONVECTION SURFACE	101,501
23	FURNACE VOLUME, CU FT	734,185
24	AIR HEATER – TYPE ROTHEMUHLE REGENERATIVE	NO. 1-PRI., 2-SEC.
25	TOTAL HEATING SURFACE, SQ FT	PRI.-250,522
26		SEC.-824,850
27	PRI. SIZE-10.6 Vu 56	
28	SEC. SIZE-12.5 Vu 68	
29	FUEL BURNER – TYPE DUAL REGISTER	
30	NO. 54	
31	PULVERIZER – TYPE MPS SIZE 89G NO. 6	
32	CAPACITY OF 5 PULV. IS 5239 M LB STEAM/HR BASED ON 48 GRI	
33	10,285 BTU COAL AT 65 % THRU 200 U.S.S. SIEVE	
34	FOR 1092 M LB COAL/PULV.-HR AT 65% THRU 200 U.S.S. SIEVE MIN. GRIND	
35	IS 42 MAXIMUM TOTAL MOISTURE IS 18% REQUIRING 570 F AIR	
36		
37		
38		
39	STEAM TEMP. CONTROL – MAIN STEAM BY SPRAY ATTEMPERATION	
40	REHEAT BY GAS RECIRCULATION	
41		
42		
43	UNIT CONSTRUCTION FEATURES – MEMBRANE WALLS	
44	BALANCE DRAFT	
45–52		
53	REVISIONS – NO.	DESCRIPTION

FLORIDA POWER CORP.
CRYSTAL RIVER, UNIT #4

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. (RS-2)
Page 4 of 6

PEF-FUEL-003738

Please find enclosed excerpts from Florida Power Corporation Application for site certification in Crystal River 4 and 5.

Table 3.2-2 Alternative Florida Power Corporation Performance Coals Weight Blends, 50/50 Basis

Type Coal	1 & 2	1 & 6	1 & 7*	2 & 4	2 & 6	2 & 7	6 & 7
Moisture, %	7.0	11.0	18.5	14.5	11.0	18.5	22.5
Volatile Matter, %	34.9	32.7	31.0	36.1	37.6	36.0	33.7
Fixed Carbon, %	49.1	45.9	42.6	42.4	42.0	38.6	35.5
Ash, %	9.0	10.4	7.9	7.0	9.4	6.9	8.3
Carbon, %	69.1	62.3	58.8	62.3	62.4	58.8	52.1
Hydrogen, %	4.7	4.3	3.9	4.5	4.6	4.2	3.7
Nitrogen, %	1.4	1.2	1.1	1.1	1.2	1.1	0.9
Chlorine, %	0.05	0.03	0.03	0.05	0.03	0.03	0.02
Sulfur, %	0.60	0.55	0.49	0.60	0.65	0.59	0.54
Oxygen, %	8.15	10.22	9.28	9.95	10.72	9.88	11.94
Gross Calorific Value, Btu/lb	12,225	11,075	10,285	10,825	10,850	10,060	8,910
Hardgrove Grindability Index	45	45	48	47	45	48	48
Ash Analysis, %							
SiO_2	46.0	49.0	40.2	48.4	50.9	40.7	44.3
Al_2O_3	23.3	23.3	18.2	19.8	22.5	17.8	18.1
TiO_2	1.0	1.0	1.0	0.8	1.0	1.1	1.0
Fe_2O_3	7.0	6.6	7.1	6.3	5.6	5.9	5.7
CaO	10.5	7.1	15.3	9.5	6.8	15.2	11.8
MgO	1.5	1.7	3.7	2.6	1.2	3.4	2.6
Na_2O	2.28	1.31	1.50	2.48	3.01	3.67	2.38
K_2O	1.01	1.28	1.20	0.43	0.82	0.60	0.96
SO_3	6.1	6.2	9.3	8.1	6.3	9.9	9.8
P_2O_5	0.44	0.24	1.1	0.55	0.28	1.24	1.00

*Performance guarantee shall be based on this blend.

Source: Black and Veatch, 1978.

Exhibit ____ (RS-3)

FPC Site Certification Documents

Florida Power
CORPORATION

RECEIVED
FEB 9 1978
DIVISION OF ENVIRONMENTAL PERMITTING

February 3, 1978
FPC 0120

Mr. Hamilton S. Oven, Jr.
Florida Department of Environmental Regulation
2562 Executive Center Circle, East
Montgomery Building
Tallahassee, Florida 32301

Subject: Crystal River Units 4 & 5
Site Certification Application
File Code: REG 2

Dear Mr. Oven:

This is in response to your request for information surrounding our Site Certification Application per our meeting in Tallahassee January 1, 1978. In regards to our proposed fuel delivery alternatives, this is to advise you that low sulfur coal for Crystal River Units 4 and 5 will be delivered to the Plant site by barge ~~from~~ the West and by unit train from the Appalachian area in approximately equal tonnages. The total requirements of these two units will be about 3,200,000 tons annually, or about 1,600,000 tons by water and 1,600,000 tons by rail. Unit trains from the Appalachian Region to Crystal River are capable of hauling 7,000 tons in seventy 100-ton cars. This will result in the need for about 229 unit train deliveries annually to supply the 1,600,000 ton Appalachian coal requirements.

Rail deliveries for existing Units 1 and 2, also in 7,000 ton unit trains, are expected to arrive at the rate of about 130 trains annually. This when combined with the anticipated rail delivery for Crystal River Units 4 and 5 will bring the annual total to 359 loaded trains or about one per day. When considering return of empty cars, there will be a total of two 70-car trains crossing US 19 almost every day.

The rail cars and motive power units will be dedicated full time to unit train coal movement to Crystal River. Terms of our tariff with the railroad will not provide for any switching at the Plant site and will require unloading and release of the train within a four-hour period during which time the engines will never be uncoupled from the cars. Upon completion of unloading, the train will leave the Plant site on a return trip to the origin coal loading mine or tipple.

A 70-car train coupled with engines and caboose will be less than three-quarters mile in length with permissible speed on our spur being 25 mph. The terms of our agreement with the State Road Department limit obstruction of traffic on US 19 to five-minute intervals; however, at the allowable train speed and with a three-quarters mile train length, crossing can be completed in less than two minutes. Combined with the expected one train per day delivery, this would result in traffic on US 19 being delayed by our unit trains under two minutes on each arrival and for another, less than two-minute interval, within the next four hours on departure of the train.

Unloading can be accomplished on a 24-hour per day, seven-day per week schedule. Since the unit trains will be in continuous service between the Plant and the origin loading point, crossing of US 19 may occur at any time during the day or night.

In regards to your request for the date of our proposed signing of coal contracts and the duration of contracts if low sulfur coal is to be used, we can only offer some general guidelines at the present. We would expect to negotiate contracts or agreements covering coal supply of from 10 to 20 year duration. Longer term options or even ownership may be a part of some of our contracts. We currently do not have an anticipated signing date for any contracts for low sulfur coal for Crystal River Units 4 and 5.

Please advise if there are questions or if we can furnish any additional information at the present time.

Sincerely,

W W Vierday

W. W. Vierday
Manager
Licensing Affairs

WWV/bz

xc: Mr. John Herrman, EPA
Mr. J. T. Rodgers
Mr. J. A. Hancock
Mr. W. S. O'Brien
Mr. R. L. Bourn
Mr. K. F. Kosky, ESE

ATTACHMENT 8

ELECTRIC FUELS CORPORATION CORRESPONDENCE

ELECTRIC FUELS CORPORATION
COAL COST AND AVAILABILITY DATA
SO_2 TASK FORCE

March 2, 1978

I. Coal Prices

A. A blend of low sulfur coal resulting in a composite level of less than 1.20 pounds $SO_2/10^6$ BTU is expected to be available at a January 1, 1978, delivered cost of $1.82 per million BTU. The exact source of these coals will be determined by both economics and availability but will rely heavily on the western coal fields and barge transportation. Coals of this sulfur level, and compatible with current design data for Units 4 and 5, are considered to be available in adequate amounts for an assured reliable supply.

B. Coal of 1 percent sulfur has a delivered cost of $1.60 per million BTU as of January 1, 1978. Utilization of this coal would result in almost total dependence on rail delivery from the Appalachian coal fields. This would lead to the loss of fixed assets already committed to a water delivery system and ignore corporate policy concerning reliability and flexibility of supply. For these reasons, the use of one percent sulfur coals should not be considered for more than one-half the total requirements of Units 4 and 5.

C. Coal with a 2 percent sulfur level would represent a blend of 1 percent sulfur coal from Appalachia and 3 percent sulfur coal from the midwest. The January 1, 1978, delivered price of this coal is $1.60 per million BTU and should be considered to be available in substantial quantities.

D. Coal with a 3 percent sulfur level is available from the midwest at a January 1, 1978, delivered price of $1.65 per million BTU. Coal of this quality is also available in substantial quantities.

II. Escalation

The escalation of delivered coal costs may vary between the various quality levels due to differences in mining conditions and transportation modes. These differences are so speculative that they are impossible to define; however, results of initial cost studies may suggest the necessity of a sensitivity analysis testing this variation. Initial studies should reflect inflation rates of 10 percent during 1978 and 1979, and 5 percent annually beyond that. It is highly probable that the next two years will see the very high escalation due to a suppressed market over the last two years, unescapable increases due to enactment of recent reclamation laws, and settlement of labor negotiations. The long term escalation beyond 1980 should reflect, and be not more than 1 percent higher than, the inflation rate assumed for other costs in this study.

III. Cancellation of Existing Contracts

The enactment of any plan which prohibits the burning of coal with 3 percent sulfur may result in contract cancellation penalties. There are two contracts, each for 500,000 tons annually, which would fall into this category. One is for a term of ten years beginning in 1978, and the other for thirteen years beginning in 1979. Assuming one was cancelled at the end of 1981 and one at the end of 1983, the following penalties should be examined:

Year	Tons	Amount
1982	500,000	$2,500,000
1983	500,000	2,500,000
1984	1,000,000	5,000,000
1985	1,000,000	5,000,000
1986	1,000,000	5,000,000
1987	1,000,000	5,000,000
1988	500,000	2,500,000
1989	500,000	2,500,000
1990	500,000	2,500,000
1991	500,000	2,500,000

Present value discounted at 9% to January 1, 1978 =

$17,650,000

The above figures represent the maximum penalty we would expect to incur with cancellation of the two subject contracts. There are various methods we might be able to terminate deliveries under these agreements. All of these would be explored in the event cancellation was required; however, it is impossible to determine the best method and the associated costs, if any, within the time frame of this study.

ELECTRIC FUELS CORPORATION
SUMMARY OF EXISTING COAL CONTRACTS
SO_2 TASK FORCE

March 2, 1978

I. Supplier - Amax Coal Company

A. Quantity: 500,000 tons annually
B. Term: 13 years
C. Start Date: 1979
D. Delivery Mode: Barge
E. BTU/LB: 11,000
F. Sulfur: 3.0%

II. Supplier - Coal Resources Corporation

A. Quantity: 425,000 tons annually
B. Term: 10 years
C. Start Date: 1978
D. Delivery Mode: Railroad
E. BTU/LB: 12,000
F. Sulfur: 1.0%

III. Supplier - Consolidation Coal Company

A. Quantity: 500,000 tons annually
B. Term: 10 years
C. Start Date: 1978
D. Delivery Mode: Barge
E. BTU/LB: 11,100
F. Sulfur: 3.0%

IV. The Hoke Company

A. Quantity: 300,000 tons annually
B. Term: Expires December 31, 1979
C. Start Date: In Effect Now
D. Delivery Mode: Barge
E. BTU/LB: 11,800
F. Sulfur: 2.25%

ATTACHMENT 9

ELECTRIC FUELS CORPORATION
CORRESPONDENCE

FUELS
CORPORATION

3201 FOURTH STREET SOUTH, P. O. BOX 15208 ST. PETERSBURG, FLORIDA 33733, (813) 866-5307

April 14, 1978

Mr. W. W. Vierday
Environmental & Licensing Affairs Department
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

Dear Bud:

SUBJECT: Crystal River 4 and 5
Information Needs

Attached please find further information relating to previous comments on Chapter 8 of the Site Certification/EIS document. This is in response to your request of April 12, 1978, and I have been in contact with Project Engineering through Frank Fusick. Please advise if there are any questions.

Very truly yours,

ELECTRIC FUELS CORPORATION

Richard L. Bourn

Richard L. Bourn
Principal Engineer

RLB/jc
Attachment
cc: Mr. E. A. Upmeyer, III
Mr. J. C. Hobbs, Jr.

INPUT INFORMATION FOR FPC'S RESPONS
TO EPA'S COMMENTS ON CHAPTER 8
File Code: ENVIRON 2-10

<u>Question #1</u> - When in full operation, the total annual coal requirements for Crystal River Units 4 and 5 will be approximately 3,300,000 tons per year depending on the heating value of the coal. Coal will generally be provided for under contracts of annual volumes no less than that required to meet a unit train movement. This may be as low as 350,000 tons annually from a single source, depending on its geographical location.

We are only now in the process of requesting firm bids for coal supplies and only those parties with the ability to demonstrate proven economically recoverable reserves and mining capability will be considered seriously as suppliers.

In addition to our discussions with suppliers on contractural agreements, we will consider the possibility of taking an equity position in the ownership of reserves and/or joint ventures in mining and preparation facilities.

Our plan has always been, and continues to be, to diversify our coal supply by bringing it from different geographical areas of the country. For the subject supply of low-sulfur coal, this includes both eastern and western coals. The bituminous coals from the Appalachian area from the Eastern United States and from the Western States of Utah and Colorado, and the sub-bituminous coals from Wyoming currently appear to be most attractive from a cost and availability standpoint. Information concerning typical prospects we are pursuing are as follows:

I. Area - Appalachia
Seams - 5-Block, Clarion, Stockton, Coalburg
Reserves - Inplace: 120,000,000 tons
Raw Recoverable: 91,000,000 tons
Clean Coal: 46,000,000 tons

Sulfur and BTU (As Received) Washed

5-Block:	0.54% S;	13,080 BTU/Lb;	0.83 $\#SO_2/10^6$ BTU
Clarion:	0.70% S;	12,580 BTU/Lb;	1.11 $\#SO_2/10^6$ BTU
Stockton:	0.66% S;	12,840 BTU/Lb;	1.03 $\#SO_2/10^6$ BTU
Coalburg:	0.73% S;	12,670 BTU/Lb;	1.15 $\#SO_2/10^6$ BTU
Weighted Average	0.71% S;	12,717 BTU/Lb;	1.12 $\#SO_2/10^6$ BTU

II. Area - Powder River Basin
Reserves - Over 400,000,000 tons

Sulfur and BTU (As Received) Raw Coal
0.33% S; 8,156 BTU/Lb; 0.81 $\#SO_2/10^6$ BTU

III. Area - Powder River Basin
Seams - Roland, Upper Smith, Lower Smith, Anderson, Deitz
Reserves - 160,000,000 tons Controlled (More possibly available)

Sulfur and BTU (As Received) Raw Coal

0.36% S; 8,164 BTU/Lb; 0.88 $\#SO_2/10^6$ BTU

IV. Area - Central Utah
Seams - Upper and Lower O'Connor
Reserves - 98,000,000 tons Controlled (More available)

Sulfur and BTU (As Received) Raw Coal

0.70% S; 11,870 BTU/Lb; 1.18 $\#SO_2/10^6$ BTU

V. Area - Somerset, Colorado
Seams - D and E
Reserves - Approximately 70,000,000 tons

Sulfur and BTU (As Received)

Raw	0.48% S;	11,430 BTU/Lb;	0.84 $\#SO_2/10^6$ BTU
Washed	0.57% S;	12,327 BTU/Lb;	0.92 $\#SO_2/10^6$ BTU

VI. Area - Appalachia
Seam - Pond Creek
Reserves - 40,000,000 tons recoverable
Sulfur and BTU (As Received) Washed Coal
0.76% S; 13,148 BTU/Lb; 1.16 $\#SO_2/10^6$ BTU

All of the examples listed are from reputable companies, and analyses and reserves can be supported by engineered exploration data and/or actual production data. These are typical of several supplies from which the principals have agreed to discuss firm offerings of production, sale of reserves, or joint participation in mining.

<u>Question #3</u> - Along with discussions of coal availability and quality from the various areas, we have also talked price. Although we have not asked for firm quotations yet, we do know within a very close tolerance what the bid prices would be. Evaluation of blocks of reserves to be considered for purchase have included detail study of mining costs, investment costs, preparation costs, and transportation costs. Florida Power Corporation's subsidiary, Electric Fuels Corporation, is involved in the construction and ownership of a transfer terminal, ocean going coal barges, ocean going tugs, and coal cars for rail delivery. Through these connections and studies, very accurate estimates of transportation costs can be developed.

Obviously, there are many factors which will influence the spread of cost between low sulfur and high sulfur coals. The major considerations in assuming the uniform percentage spread in this cost differential is as follows:

a) Transportation costs for coal delivered into Florida are a substantial portion of the delivered cost and will, in some cases, exceed the cost of the coal itself. For our situation then, the future cost of any delivered coal will be nearly as much dependent on rates of escalation on transportation, applicable to both high and low sulfur coals, as to the mine cost of the coal itself.

b) We are looking at both underground and surface mining for both high sulfur and low sulfur coals. Mining costs for similar type operations will escalate at uniform rates independent of sulfur level.

c) Many people feel that the cost of low sulfur coal will increase very rapidly due to demand. While coal of less than 0.6 pounds of sulfur per million BTU is in scarce supply relative to all other coals with sulfur levels higher than this, enactment of the 1977 Clean Air Act will greatly reduce the demand for compliance quality coals. There is evidence now that the availability of very economically recoverable low sulfur coals from the West is exceeding demand. This over commitment to supply and lack of market will help keep down the prices of very low sulfur coals.

During the course of our discussions with producers, we have from time to time received copies of pro forma contracts. It is not unusual to find that producers of either high sulfur or low sulfur coals will suggest the use of common indices for cost escalation.

Even though the referenced fuel study used equal escalation rates for both high and low sulfur coals, the economic choice of low sulfur coal has been reaffirmed starting with 1978 cost differentials as high as

13.75 percent and reaching a differential as high as 25.25 percent over a twenty year period.

Question #4 - Escalation rates used to project any costs into the future are highly speculative, and only time can verify or disprove the accuracy of any assumed escalation factor. We believe that escalation over the next two years will be high, about 10 percent, as the full impact of the recent UMWA contract settlement, the Federal Surface Mining Control and Reclamation Act of 1977, and The Black Lung Benefits Revenue Act of 1977 are added to the cost of coal. These increases will affect cost of coals at different rates depending on mining technique and are not related to sulfur content.

Beyond the two year time frame, we believe there will be a leveling off and reduction in the rates of escalation. This is predicated on a belief that most of the effects of recent regulations will have already been realized, and the coal industry will have stabilized beyond its current level of activity. We believe this will result in escalation rates of about 5 percent annually.

RLB
EFC
4/14/78

Exhibit ____ (RS-4)

FPC Coal Documents

1980 Site Certification Application

Please find enclosed excerpts from Florida Power Corporation Application for site certification in Crystal River 4 and 5.

3.2 FUEL

3.2.1 FUEL TYPES AND QUANTITIES

Coal supply contracts for the Crystal River Plant Units 4 and 5 are not yet complete. Plans are to utilize coal, or a blend of coals, which will meet the EPA sulfur emission standards without the use of flue gas scrubbers.

The coals which will provide compliance with the EPA standards are found in two geographical regions of the country, principally in the far western coal fields, and in the Appalachian coal fields. The Appalachian coals generally are a high quality, high Btu, high ash fusion, low sulfur coal. The western coals generally are of lower quality, and have lower Btu, higher ash, and higher moisture, but they are extremely low sulfur coals.

The proposed design coal for the Crystal River Units 4 and 5 is a 50/50 blend of a typical Appalachian and western coal. The various coals used to select the design blend are listed in Table 3.2-1. Fuel and ash analyses for the design blends are shown in Table 3.2-2. A 50/50 weight blend of Eastern Province and Campbell County, Wyoming coals (Nos. 1 and 7) were selected as the basis for the performance guarantee.

At the rated output (695 Mw gross), and the design blend coal heating value of approximately 23,923 kJ/kilograms (10,285 Btu per pound), the coal consumption will be approximately 294,000 kilograms (648,000 pounds) per hour for each unit. The average coal consumption per year over the 30-year life of Units 4 and 5 will be approximately 1,700,000 metric tons (1,870,000 tons) per year for each unit, based on a 0.66 annual average capacity factor.

Auxiliary fuel for furnace warm-up and coal ignition during start-up will be fuel oil. Diesel fuel and gasoline will be used to power the

Table 3.2-1 Alternative Coal Sources

	Typical		Range Minimum	Range Maximum
Type (1)				
Eastern Province				
Ala., C. Ky., Tenn., Southern W. Va.				
Moisture, %	7.0		4.0	12.0
Volatile matter, %	30.0		(28.0)	--
Fixed carbon, %	51.0		--	--
Ash, %	16.4		--	(16.0)
Carbon, %	77.0		--	--
Hydrogen, %	4.4		--	--
Nitrogen, %	1.4		--	--
Sulfur, %	0.50		--	0.8
Chlorine, %	0.05		--	(0.15)
Oxygen, % (by difference)	7.65		--	--
Gross calorific value, Btu/lb	12,450		11,000	13,000
Hardgrove Grindability Index	45		38	65
Ash Fusibility, %	**Red.**	**Oxid.**	**Reduction**	
ID	2,250	2,350	--	--
ST	2,300	2,400	2,200	2,700+
HT	2,330	2,440	--	--
FT	2,350	2,475	--	--
Ash Analysis, %				
P_2O_5	0.40		--	--
SiO_2	45.0		--	--
Fe_2O_3	8.0		--	18.0
Al_2O_3	24.0		--	--
TiO_2	1.0		--	--
CaO	10.5		--	--
MgO	2.0		--	--
K_2O	1.50		--	--
Na_2O	0.50		--	0.80
SO_3	6.0		--	--

Table 3.2-1 Alternative Coal Sources (Continued, page 7 of 8)

	Typical		Range Minimum	Range Maximum
Type (7)				
Campbell Co., Wyoming				
Moisture, %	30.0		27.0	32.0
Volatile matter, %	12.1		--	--
Fixed carbon, %	32.1		--	--
Ash, %	5.8		(6.5)	(11.0)
Carbon, %	48.50		--	--
Hydrogen, %	3.40		--	--
Nitrogen, %	0.70		--	--
Sulfur, %	0.48		--	--
Chlorine, %	0.02		(0.01)	(0.06)
Oxygen, % (by difference)	11.10		--	--
Gross calorific value, Btu/lb	8,125		7,700	8,600
Hardgrove Grindability Index	52		50	60
Ash Fusibility, %	Red.	Oxid.	Reduction	
ID	2,060	2,070	--	--
ST	2,120	2,160	2,000	2,300
HT	2,140	2,180	--	--
FT	2,180	2,220	--	--
Ash Analysis, %				
P_2O_5	2.0		--	--
SiO_2	34.0		--	--
Fe_2O_3	6.0		--	--
Al_2O_3	13.0		--	--
TiO_2	1.0		--	--
CaO	20.0		--	--
MgO	6.0		--	--
K_2O	0.8		--	--
Na_2O	2.8		1.0	4.0
SO_3	13.7		--	--

Table 3.2-2 Alternative Florida Power Corporation Performance Coals Weight Blends, 50/50 Basis

Type Coal	1 & 2	1 & 6	1 & 7*	2 & 4	2 & 6	2 & 7	6 & 7
Moisture, %	7.0	11.0	18.5	14.5	11.0	18.5	22.5
Volatile Matter, %	34.9	32.7	31.0	36.1	37.6	36.0	33.7
Fixed Carbon, %	49.1	45.9	42.6	42.4	42.0	38.6	35.5
Ash, %	9.0	10.4	7.9	7.0	9.4	6.9	8.3
Carbon, %	69.1	62.3	58.8	62.3	62.4	58.8	52.1
Hydrogen, %	4.7	4.3	3.9	4.5	4.6	4.2	3.7
Nitrogen, %	1.4	1.2	1.1	1.1	1.2	1.1	0.9
Chlorine, %	0.05	0.03	0.03	0.05	0.03	0.03	0.02
Sulfur, %	0.60	0.55	0.49	0.60	0.65	0.59	0.54
Oxygen, %	8.15	10.22	9.28	9.95	10.72	9.88	11.94
Gross Calorific Value, Btu/lb	12,225	11,075	10,285	10,825	10,850	10,060	8,910
Hardgrove Grindability Index	45	45	48	47	45	48	48
Ash Analysis, %							
SiO_2	46.0	49.0	40.2	48.4	50.9	40.7	44.3
Al_2O_3	23.3	23.3	18.2	19.8	22.5	17.8	18.1
TiO_2	1.0	1.0	1.0	0.8	1.0	1.1	1.0
Fe_2O_3	7.0	6.6	7.1	6.3	5.6	5.9	5.7
CaO	10.5	7.1	15.3	9.5	6.8	15.2	11.8
MgO	1.5	1.7	3.7	2.6	1.2	3.4	2.6
Na_2O	2.28	1.31	1.50	2.48	3.01	3.67	2.38
K_2O	1.01	1.28	1.20	0.43	0.82	0.60	0.96
SO_3	6.1	6.2	9.3	8.1	6.3	9.9	9.8
P_2O_5	0.44	0.24	1.1	0.55	0.28	1.24	1.00

*Performance guarantee shall be based on this blend.

Source: Black and Veatch, 1978.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-4)
Page 5 of 11

emergency fire pumps and mobile coal and ash handling equipment. Average fuel oil consumption will be approximately 10,600 cubic meters (2,800,000 gallons) per year for each unit, based on 200 starts per year.

3.2.2 FUEL TRANSPORTATION

In order to maintain a diversity of supply, approximately 50 percent of the coal will be transported to the Crystal River site by unit trains and 50 percent will be transported to the site in oceangoing barges.

The Appalachian coal will be transported in 70- to 110-car unit trains of approximately 90.7-metric ton (100-ton) capacity cars. An average of 4 to 6 trains per week will be required to supply 50 percent of the coal, assuming the present projections for plant capacity factors.

The western coals will be transported from the coal fields to the Mississippi River by unit rail trains, loaded in river barges, and transported down the Mississippi to the New Orleans, Louisiana area. The coal will then be loaded into oceangoing transportation units that will carry it across the Gulf of Mexico to the Crystal River site. The existing coal-receiving facilities at the Crystal River site will be used. This system is designed to unload barges of up to 13,608 metric tons (15,000 tons) capacity. An average of about 3 barges per week will be required.

Fuel oil and gasoline auxiliary fuels will be received at the plant by truck or rail, depending on the supplier.

3.2.3 COAL HANDLING FACILITIES

EXISTING FACILITIES

The coal-handling facilities at the plant for Units 1 and 2 include a barge and tug mooring dock, a Dravo clamshell-type barge unloader, a Dravo stacker-reclaimer, and an integrated single-belt conveyor system connecting the barge unloader and stacker-reclaimer. In addition to the barge unloading facilities, a railcar unloading facility is provided to serve the existing units. This installation includes a railroad loop track for coal delivery and unit train turnaround, an elevated structure for bottom dumping of railcars, and a belt conveyor linking the dump structure with a radial stacker. The radial stacker will generate a coal pile which can be moved by mobile equipment to a reclaim hopper and associated conveyor. The reclaim hopper conveyor will discharge to the transfer house located at the tailpoint of the stockout and reclaim system yard belt. These facilities are physically located south and southeast of the existing units as shown in Figure 3.2-1.

UNITS 4 AND 5 FACILITIES

The existing coal yard and terminal facilities will be modified and expanded to improve the capability and reliability of the system for the four-unit installation. Figure 3.2-2 illustrates schematically how the proposed facilities will be added to existing facilities.

Additions to the existing facilities for Units 4 and 5 will include the following:

1. Two new stockout and reclaim systems for the active storage piles serving the new units;
2. A coal-blending facility;
3. Additional coal-crushing facilities;
4. A series of conveyors linking the unloading, active storage, blending, and crusher facilities in the coal yard area and a dual belt system connecting the coal yard and the silos in each generating unit. The conveyor system would include associated transfer facilities at belt intersections.

The physical locations of the above-listed facilities are shown in Figure 3.2-1.

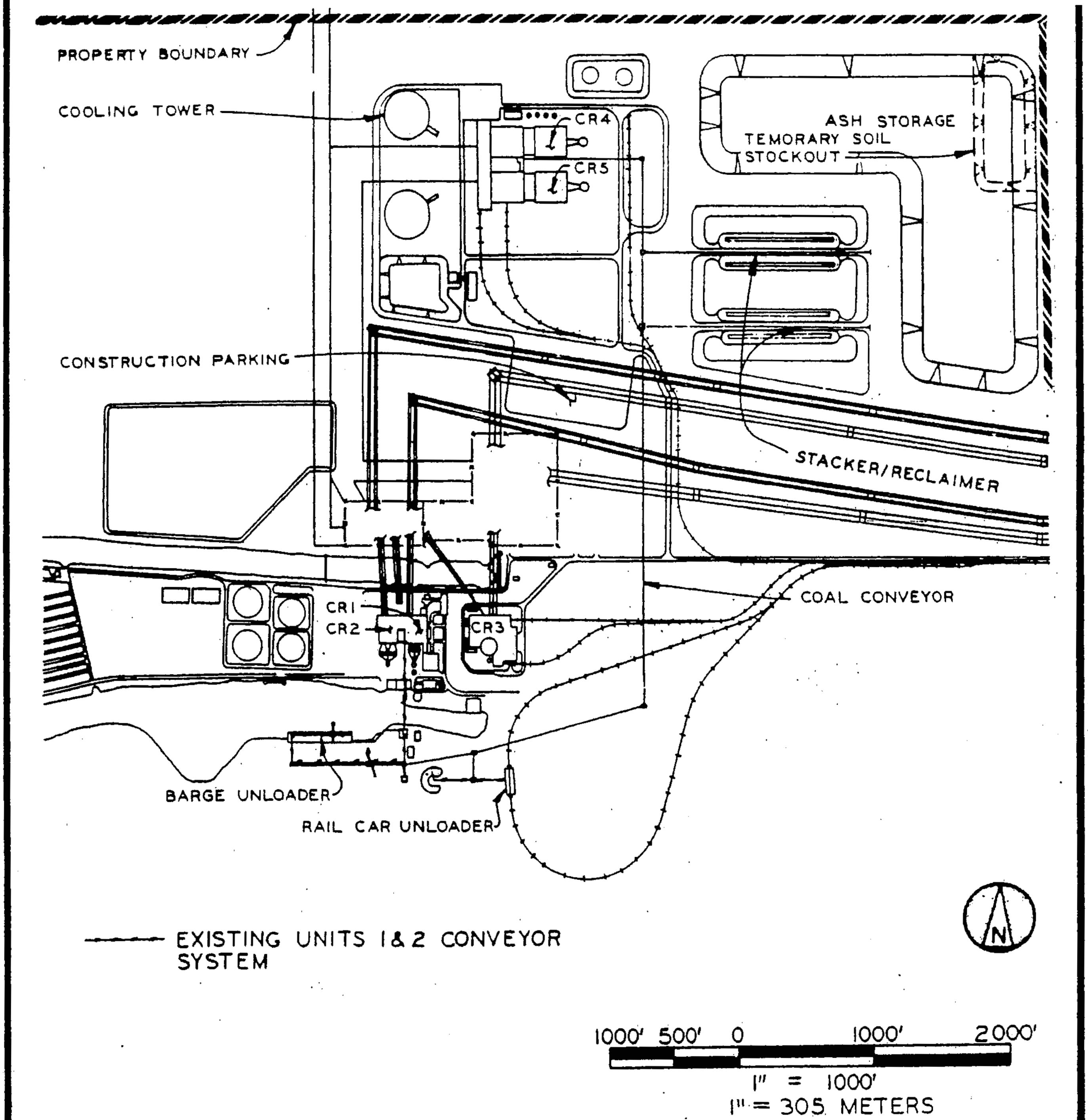


Figure 3.2-1

COAL HANDLING FACILITIES-CRYSTAL RIVER SITE

SOURCE: BLACK AND VEATCH, 1980

FLORIDA POWER CORPORATION

PROPOSED
CRYSTAL RIVER UNITS 4 & 5

CITRUS COUNTY, FLORIDA

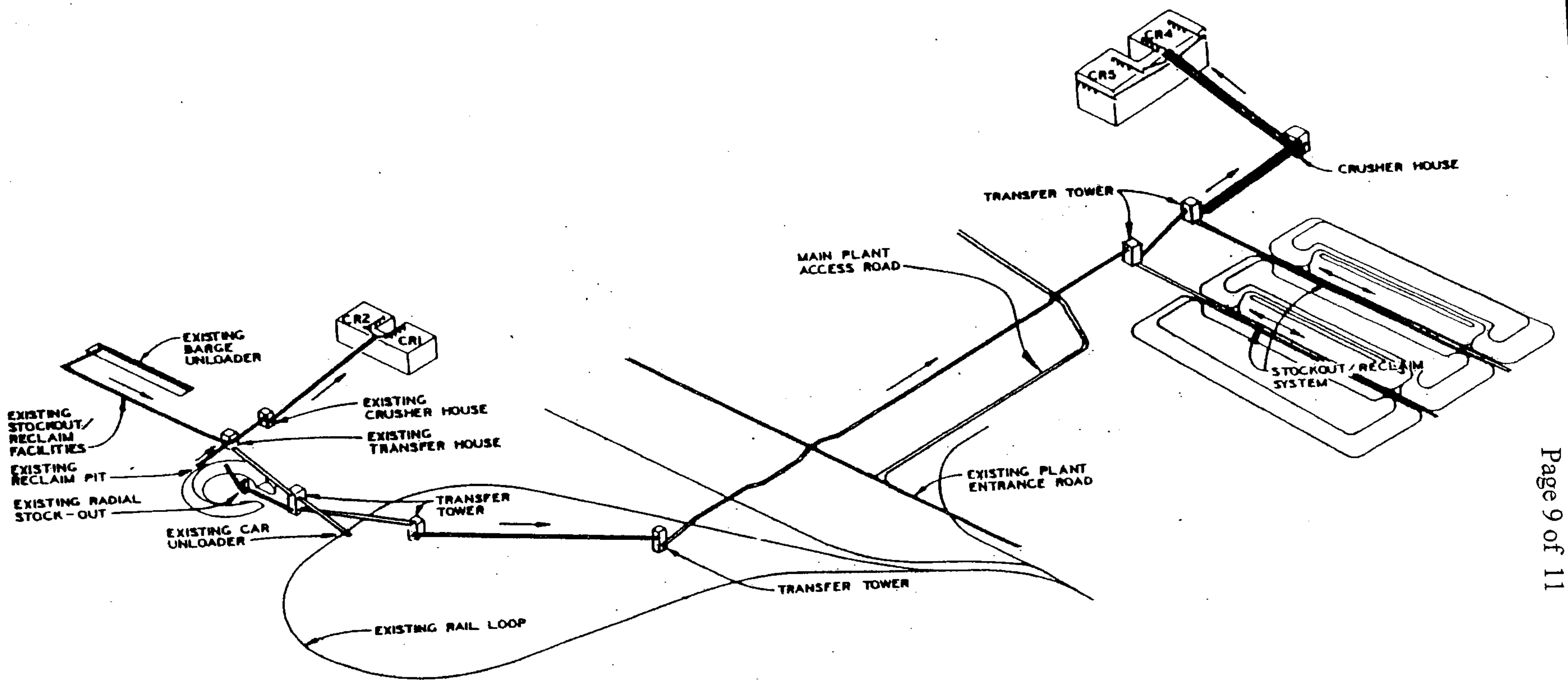


Figure 3.2-2
COAL HANDLING FACILITIES ISOMETRIC

SOURCE: BLACK AND VEATCH, 1980

FLORIDA POWER CORPOR

PROPOSED
CRYSTAL RIVER UNITS 4 & 5

CITRUS COUNTY, FLORIDA

3.2.4 FUEL STORAGE

EXISTING FACILITIES

The existing Crystal River Plant Units 1 and 2 utilize three types of coal storage: in-plant, active, and inactive. During normal operation, coal is dumped from the train cars, or removed from the barges, and transported by a system of conveyors and hoppers to the in-plant storage silos. When the in-plant storage silos are full, the coal is diverted to the active storage piles by the stacker- reclaimer. Active storage provides a buffer between rapid but intermittent unloading of coal trains and barges, and slower but steady coal consumption by the plant. The inactive storage is used for periods when the supply of coal is interrupted, such as for equipment failures, labor disputes, or variations between coal purchase contractual commitments.

UNITS 4 AND 5 FACILITIES

Units 4 and 5 will utilize the same three types of coal storage as are used for Units 1 and 2. In-plant storage will be provided for each unit in 6 or 7 silos. Both active and inactive storage will be provided in the area adjacent to the ash storage facility. This area will provide approximately 39,000 metric tons (43,000 tons) of active storage and 776,300 metric tons (885,000 tons) of inactive storage, and will cover approximately 111,000 square meters (27.5 acres). An additional storage of 80,000 square meters (20 acres) will be located adjacent to the stacker-reclaimer system.

The total active storage of 39,000 metric tons (43,000 tons) will provide approximately 8 days' fuel requirements for both units operating at 90 percent capacity. The average resident time for coal in the active storage areas will be 50 to 60 hours, based on the present projections of plant capacity.

dioxide emission rate to 520 nanograms per joule (1.2 pounds per million Btu) heat input.

A stack height of approximately 183 meters (600 feet) and a diameter of 6.86 meters (22.5 feet) for each unit is adequate to satisfy dispersion requirements. Each chimney will be capable of discharging approximately 1,038 m^3/s (2,200,000 ACFM) of flue gas at 127°C (260°F) and 28.1 m/s (99.2 f/s). The flue gas flowrate and emissions are presented in Table 3.7-2.

COAL AND ASH HANDLING

The coal and ash handling system will generate particulate matter from handling ~~western~~ coal and dry fly ash. Observed unloading of Western coals at a number of utilities indicates that there is considerable dust emission even though western coals have ~~a~~ relatively high total moisture content. The probable cause of high dust emission is the more friable nature of western sub-bituminous coals as compared to midwestern or eastern bituminous coals. The emissions become more severe as the coal moves through a typical handling system. Natural drying action takes place in handling as the size of the coal is reduced, causing significantly greater dust emissions in transfer and silo areas. The handling of mideastern and eastern coals in the systems does not create as much dust as do western coals, although the emissions are sufficient to require dust-collecting equipment.

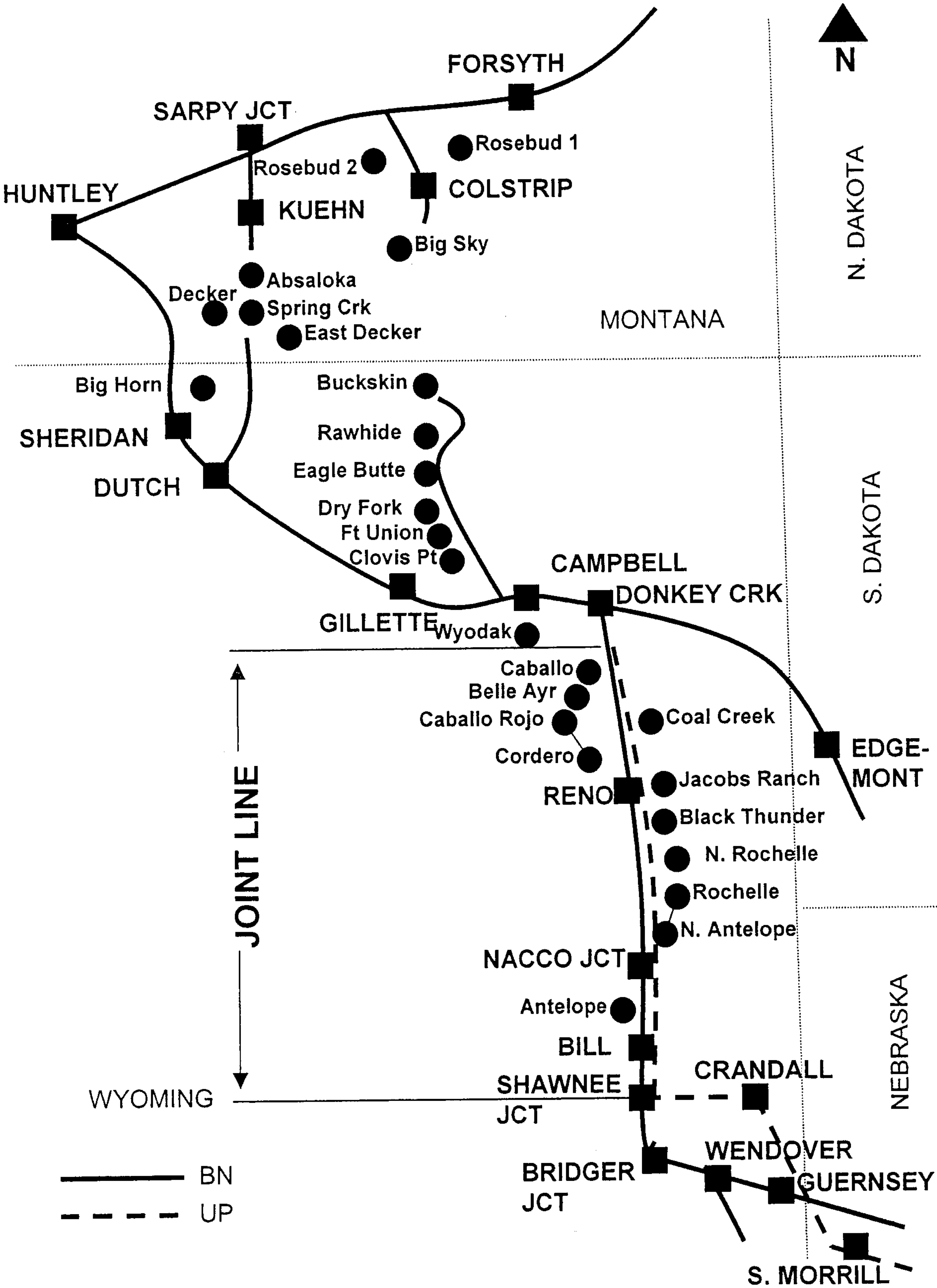
The major emission points will be the coal conveyor transfer points, crusher house, coal silos, fly ash silos, fly ash vacuum pump discharge and emergency reclaim hopper.

Coal will be transferred by covered conveyor from the existing coal handling area to Units 4 and 5 storage. At the storage area, coal will be blended and ~~transferred~~ to the ~~crusher~~ house by covered conveyor. Five transfer points are designed in the conveying system.

Exhibit ____ (RS-5)

PRB Development

POWDER RIVER BASIN



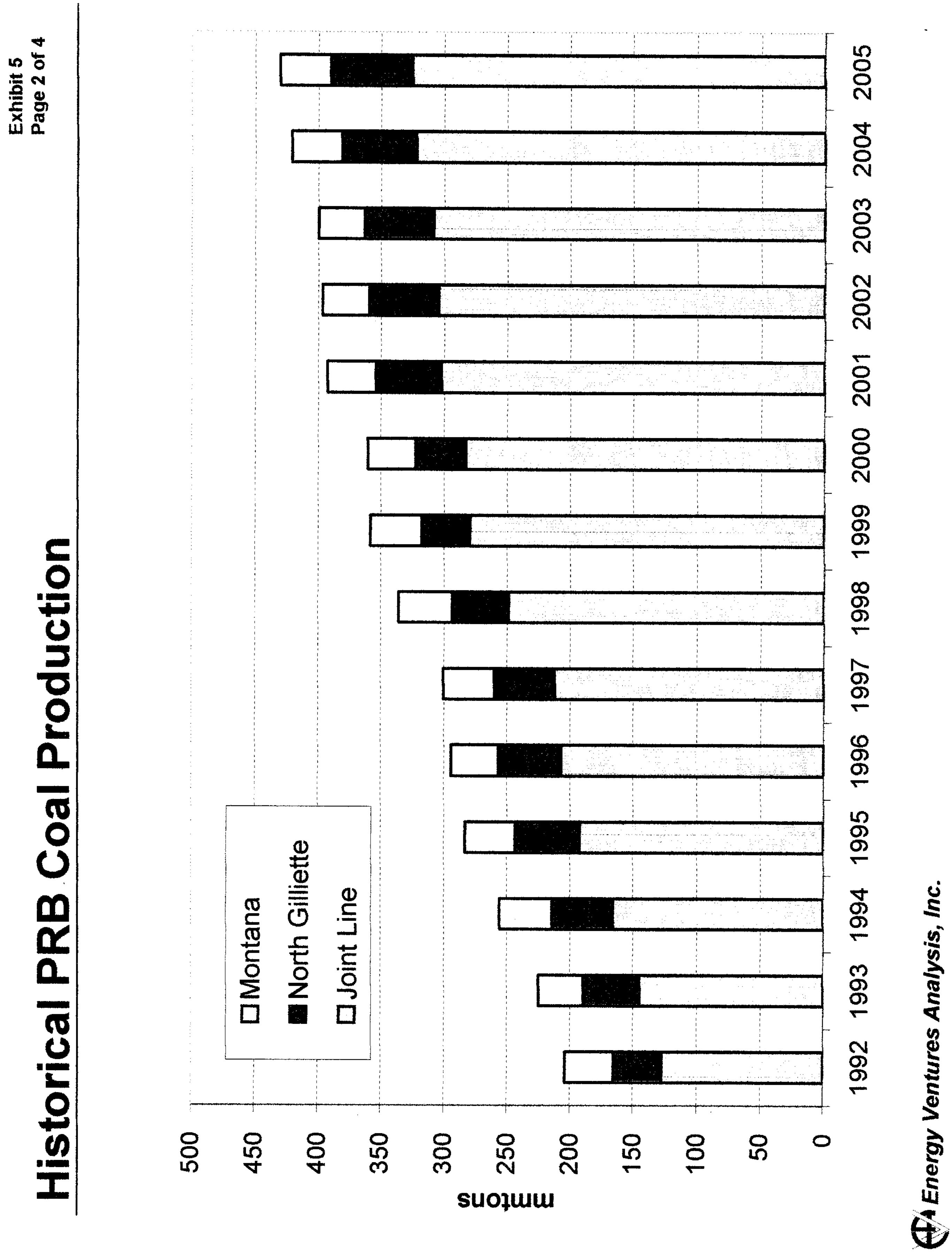


Exhibit 5
Page 2 of 4
Historical PRB Coal Production
Montana
North Gilliette
Joint Line
mmtons
500
450
400
350
300
250
200
150
100
50
0
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Energy Ventures Analysis, Inc.

Exhibit ___ (RS-5)
Page 3 of 4

PRB Mine Production By Rail Service

Mine	Company	Production (1,000 Tons)					Changes From 1990-1998	
		1985	1990	1996	1997	1998	1,000 Tons	Annual Change
Single Line (BNSF)								
• *High Btu (>8,500 Btu/lb) Montana*								
Absaloka	WRI	3,112	4,498	4,668	7,060	6,708	2,210	5.1%
Big Horn	Kiewit	2,363	135	15	0	0	-	-
Big Sky	Peabody	3,235	3,603	4,995	4,335	3,488	(115)	-0.5%
Decker	Decker	6,196	9,277	10,979	11,873	10,476	1,199	1.5%
Rosebud	Wes Energy	12,308	13,785	7,740	9,125	10,527	(3,258)	-3.3%
Spring Creek	Kennecott	2,837	7,133	9,015	8,306	11,313	4,180	5.9%
Single Rail High Btu Subtotal		*30,051*	*38,431*	*37,412*	*40,699*	*42,512*	*4,081*	*1.3%*
• *Low Btu (<8,500 Btu/lb) Montana*								
Buckskin	Triton	3,975	6,435	11,952	14,443	17,142	10,707	13.0%
Rawhide	Peabody	12,237	11,767	15,068	10,706	5,306	(6,461)	-9.5%
Fort Union	Kennecott	533	29	559	593	0	-	-
Eagle Butte	Cyprus Amax	11,808	13,922	15,700	17,920	18,074	4,152	3.3%
Dry Fork	West. Fuels	-	2,787	2,986	915	923	(1,864)	-12.9%
Clovis Point	Black Hills	1,424	-	200	0	0	-	-
Single Rail Low Btu Subtotal		*29,977*	*34,940*	*46,465*	*44,577*	*41,445*	*6,505*	*2.1%*
Subtotal Single Rail		***60,028***	***73,371***	***83,877***	***85,276***	***83,957***	***10,586***	***1.7%***
Joint Line (BNSF and UP)								
• *Low Btu (<8,500 Btu/lb) Wyoming*								
Caballo	Peabody	8,978	15,267	22,003	19,947	25,985	10,718	6.9%
Belle Ayr	Cyprus Amax	12,829	14,748	19,970	22,801	22,483	7,733	5.4%
Caballo Rojo[1]	Kennecott	4,222	9,383	15,084	3,446	1	1	-
Cordero[1]	Kennecott	10,085	13,763	12,861	24,617	36,979	13,833	6.0%
Coal Creek	Arch	2,215	151	5,804	2,921	7,068	6,917	-
Joint Line Low Btu Subtotal		38,329	53,312	75,722	73,732	92,515	39,202	7.1%
• *High Btu (>8,500 Btu/lb) Wyoming*								
Jacobs Ranch	Kennecott	12,968	17,744	24,523	27,113	29,251	11,507	6.4%
Black Thunder	Arch	23,158	30,852	39,175	37,670	42,683	11,831	4.1%
Rochelle	Peabody	211	12,704	26,248	24,940	64,640[2]	42,287[2]	14.2%
N. Antelope	Peabody	5,713	9,649	26,623	34,965	-	-	-
Antelope	Kennecott	-	5,212	12,048	13,585	19,419	14,207	17.9%
N. Rochelle	Triton					41	-	-
Joint Line High Btu Subtotal		*42,050*	*76,161*	*128,617*	*138,273*	*156,034*	*79,873*	*9.4%*
Subtotal Joint Line		***80,379***	***129,473***	***204,339***	***212,005***	***248,549***	***119,076***	***8.5%***
Total Rail		**140,407**	**202,844**	**288,216**	**297,281**	**332,506**	**129,662**	**6.4%**

1 Operations at Cordero and Caballo Rojo were combined in 1997.

2 Operations at Rochelle and N. Antelope were combined in 1998.

Source: MSHA Form 7000-2.

Exhibit ___ (RS-5)
Page 4 of 4

1998 Wyoming PRB Mines

Mine	Quantity (000 Tons)	Quality (Btu/lb)	SO_2 Emissions (lbs./MMBtu)
BNSF Only (Low Btu)			
Buckskin	17,093.4	8,427	1.15
Dry Fork	982.5	8,159	0.92
Eagle Butte	19,847.7	8,419	0.85
Rawhide	5,114.2	8,323	0.72
Total	**43,037.8**	**8,332**	**0.91**
Joint Line UP and BNSF (Low Btu)			
Belle Ayr	20,126.4	8,556	0.64
Caballo	20,107.7	8,485	0.83
Codero Rojo	33,415.7	8,416	0.77
Coal Creek	9,062.1	8,423	0.81
Total	**82,712.0**	**8,470**	**0.76**
Joint Line UP and BNSF (High Btu)			
Antelope	15,826.5	8,814	0.61
Black Thunder	44,128.3	8,752	0.78
Jacobs Ranch	27,607.8	8,711	0.99
North Rochelle	52.7	8,617	0.67
Rochelle/N. Antelope	61,096.0	8,786	0.46
Total	**148,711.3**	**8,736**	**0.70**

Note: Quality and emissions are weighted averages.

Exhibit ____ (RS-6)

EPRI & DOE PRB Studies

DOE/EIA-0597(2000)

Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation

October 2000

Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
Washington, DC 20585

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-6)
Page 2 of 9

Electric Utility Phase I

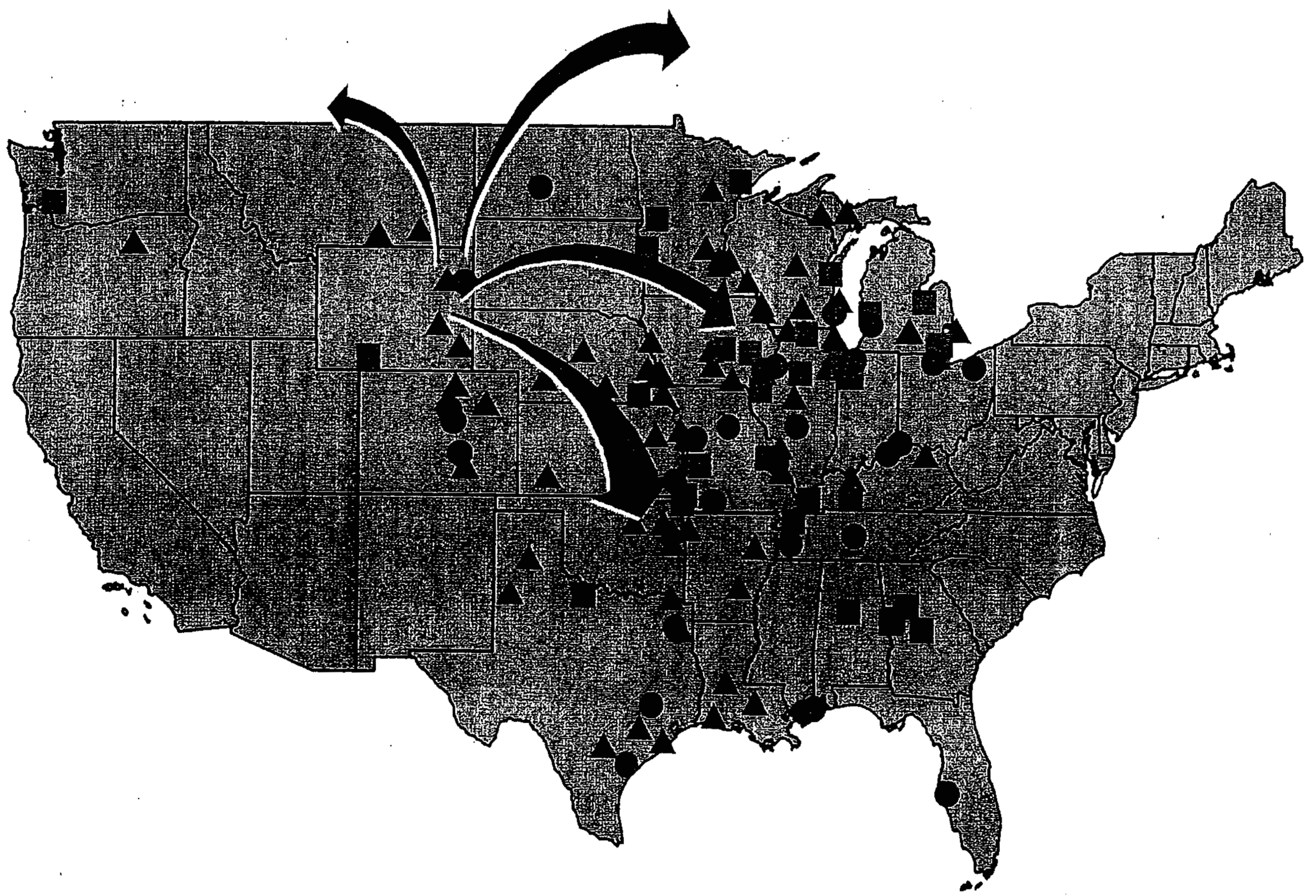
Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990

March 1994

Energy Information Administration

Impact of Powder River Basin Coal on Power and Fuel Markets

LICENSED MATERIAL



Docket No. 060658
Testimony of OPC witness Sansor
Exhibit No. __ (RS-6)
Page 4 of 9

Impact of Powder River Basin Coal on Power and Fuel Markets

TR-109000

Final Report, July 1998

EPRI Project Manager
J. Platt

EPRI 3412 Hillview Avenue, Palo Alto, CA 94304 PO Box 10412

Powder River Basin Coal Supply and Suitability

EPRI Report Series on Low-Sulfur Coal Supplies

IE-7119
Research Project 3199-08

Final Report, December 1992

Prepared by
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Engineering and Economic Evaluations Program
Integrated Energy Systems Division

The Emission Allowance Market and Electric Utility SO_2 Compliance in a Competitive and Uncertain Future

Prepared by
Keith D. White, El Cerrito, CA
Energy Ventures Analysis, Inc., Arlington, VA
Van Horn Consulting, Orinda, CA

LICENSED MATERIAL

ELECTRIC POWER RESEARCH INSTITUTE

EPRI
Electric Power
Research Institute

Keywords:
Acid rain
Coal pricing
Flue gas desulfurization
Strategic planning
Coal markets—Northern Appalachia,
Illinois, and Indiana
Natural gas

Projects 2369-53, 3199-6
Final Report
June 1991

Energy Ventures Analysis, Inc

Utility Coal Markets Under Acid Rain Legislation

Prepared by
ENERGY VENTURES ANALYSIS, INC., Arlington, Virginia

EPRI
Electric Power
Research Institute

Keywords:
Acid rain
Low-sulfur coal costs
Coal transportation costs—railroad, barge
Powder River Basin
Central Appalachia

Final Report
September 199

Coal Transportation Risks for Fuel Switching Decisions

Volume 1: Powder River Basin and Inland Waterways

EPRI Report Series on Low-Sulfur Coal Supplies

Prepared by
THE FIELDSTON COMPANY, INC., Washington, D.C.

LICENSED
MATERIAL

(continued on back cover)

POWDER RIVER BASIN COAL SUPPLY AND SUITABILITY

Prepared By:

Energy Ventures Analysis, Inc
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Principal Investigators
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Dr Ralph W Barbaro
Dr Robert L Sansom
William R Glover

Prepared For:

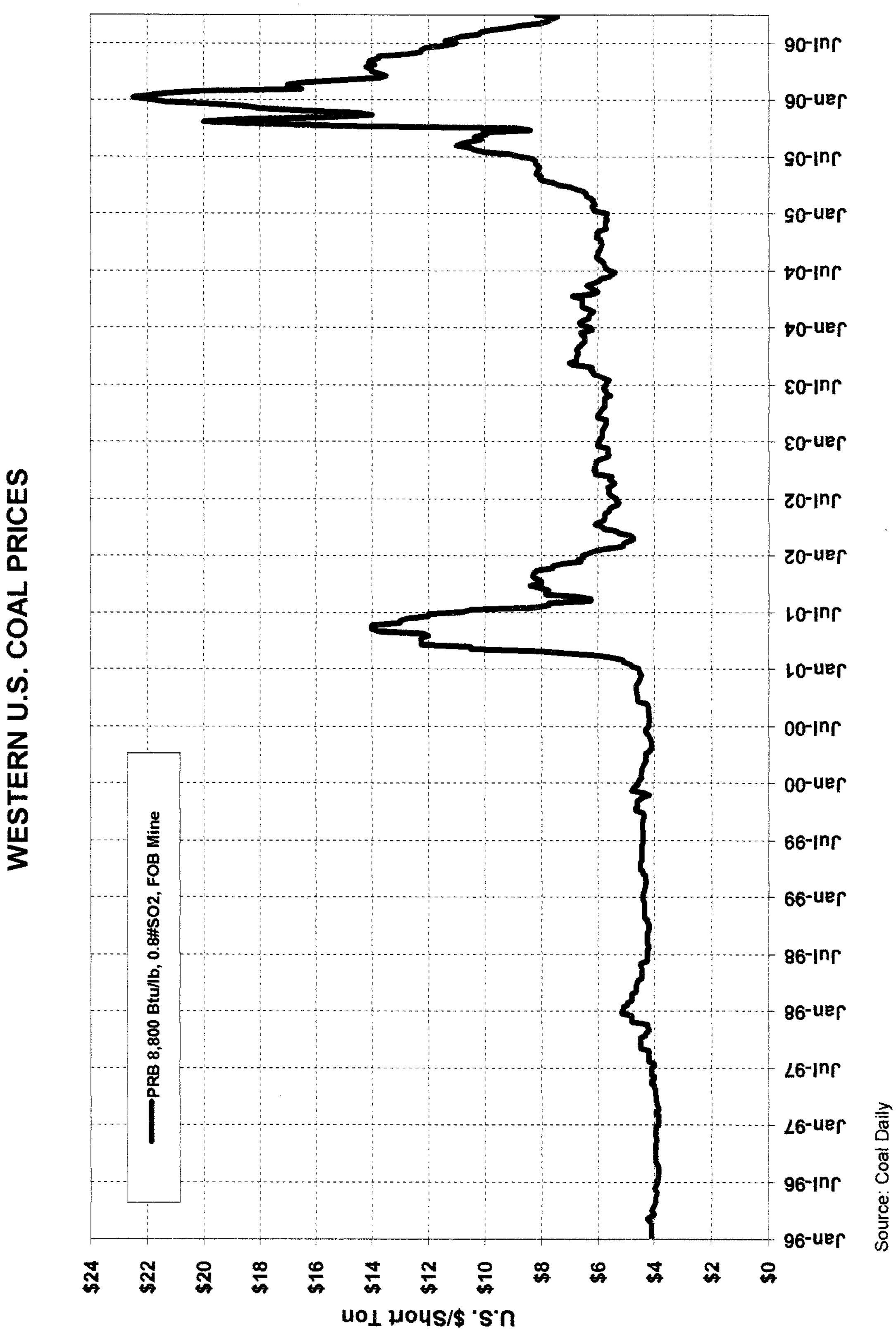
Integrated Energy Systems Division
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

Project Manager
J Platt

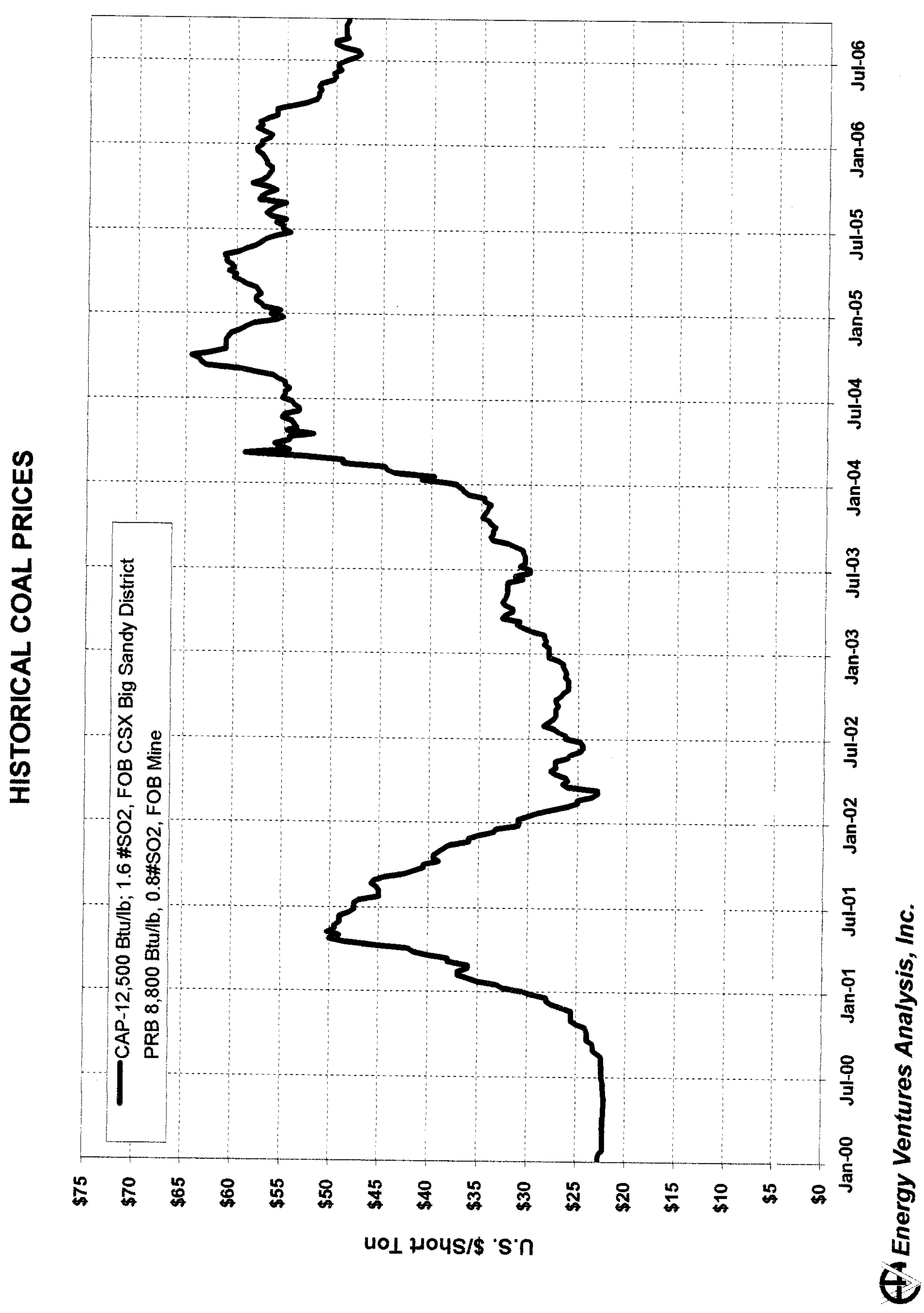
December 1992

Exhibit ____ (RS-7)

Coal Prices



Energy Ventures Analysis, Inc.


HISTORICAL COAL PRICES
CAP-12,500 Btu/lb; 1.6 #SO2, FOB CSX Big Sandy District
PRB 8,800 Btu/lb, 0.8#SO2, FOB Mine
U.S. $/Short Ton
$75
$70
$65
$60
$55
$50
$45
$40
$35
$30
$25
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$10
$5
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Energy Ventures Analysis, Inc.

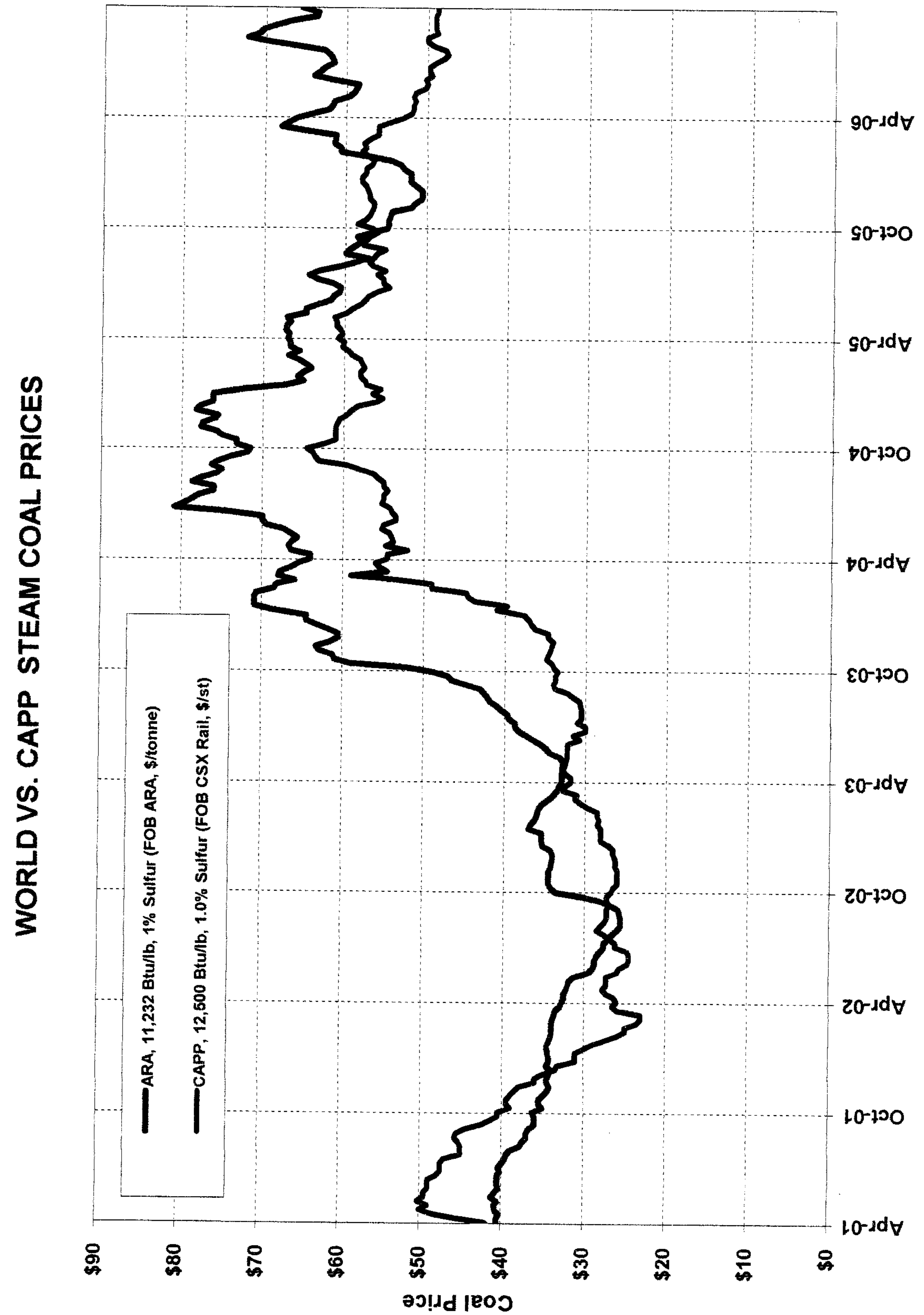

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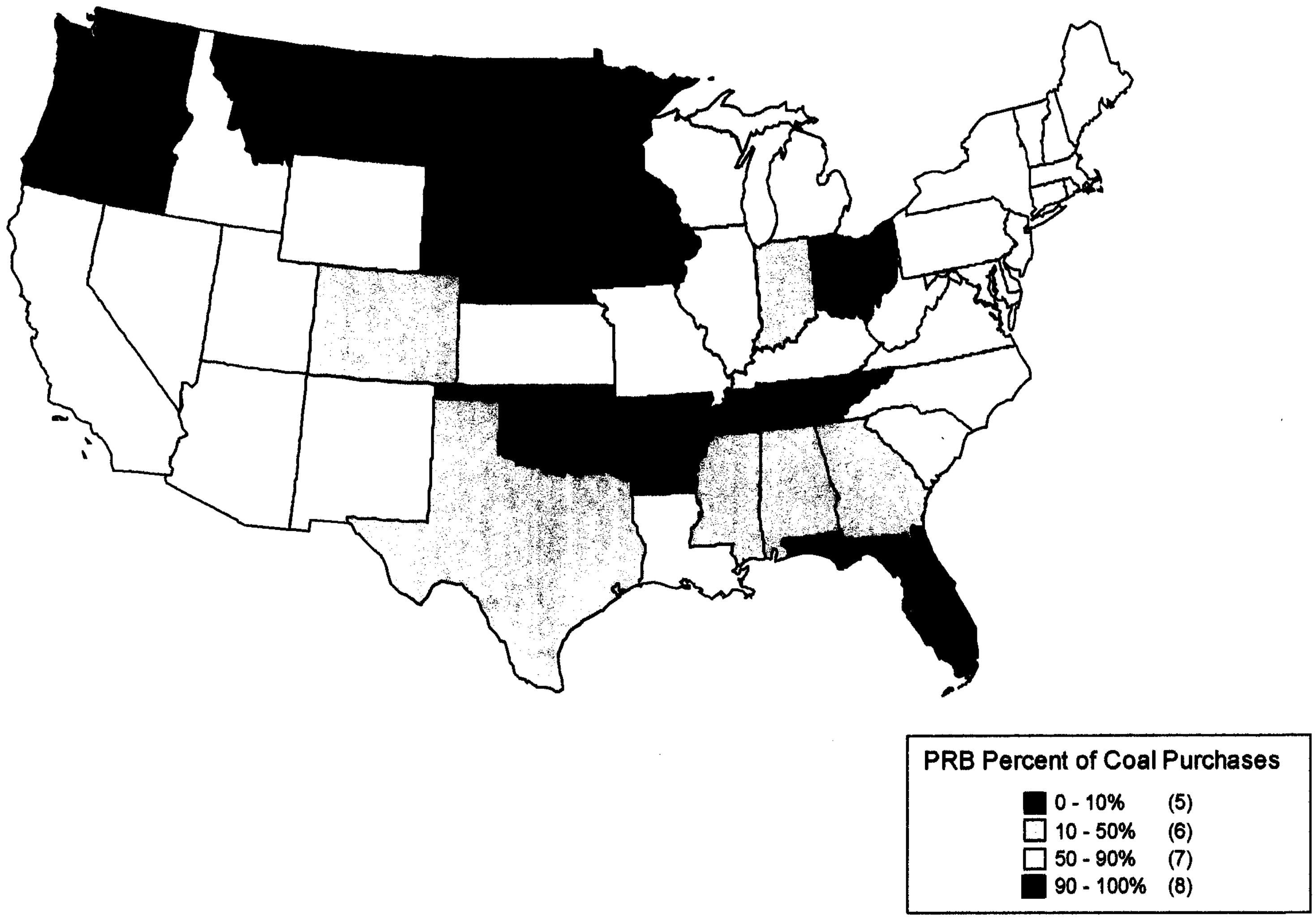
Exhibit ____ (RS-8)

Map of 1996 PRB Shipments

1996 PRB SHARE OF UTILITY COAL PURCHASES



Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. _ (RS-8)
Page 1 of 1

Exhibit ____ (RS-9)

PRB Shipments to Southeastern Plants

Exhibit ___ (RS-9)
Page 1 of 1

PRB Shipments To Southeast Plants
(000 Tons)

Year	Georgia Power Scherer	Alabama Power Miller	Gulf/Miss. Power Daniel	Mississippi Power Watson[3]	TECO To[4] Electro Coal Terminal For Gannon
1994	2,600	0	0		
1995	5,700	2,700	1,200		
1996	6,800	3,600	2,100		590
1997	5,300	5,200	3,200		970
1998	6,200	6,000	2,800	464	1,064
1999	6,800	10,200	2,000	201	430
2000	9,150	11,300	450	285	617
2001	6,600	10,800	54[2]		632
2002	6,400	10,300			337
2003[1]	8,400	10,100			Gannon
2004[1]	14,200	11,000			Closed

Source: FERC Form 423.

1 Scherer 1&2 converted to PRB.

2 Daniel, not designed for PRB coal suffers a derate when burning PRB coal. In 2001 it shifted to 100% western bituminous (Colorado) coal.

3 Not designed for PRB coal. Received PRB by BNSF single-haul rail to McDuffie Terminal at Mobile then via barge to Watson for blending.

4 PRB coal BNSF rail to Cook Terminal on lower Ohio River then via TECO barge to TECO's Terminal in New Orleans.

Exhibit ____ (RS-10)

Delivered PRB Coal Costs

Exhibit ___ (RS-10)
Page 1 of 1

Delivered PRB Coal Cost

Year	Delivered PRB Coal Cost ($/MMBtu)				
	TECO PRB To TECO Bulk Terminal	To: Georgia Power Scherer By Rail 1,800 Miles	To: Alabama Power Miller BNSF To Birmingham	To: Gulf Power Daniel, MS	To: Miss Pwr Watson via McDuffie Plus Barge
1994		1.50		1.38	
1995		1.52	1.07-1.14	1.40	
1996	1.42	1.52	1.13	1.30-1.41	
1997	1.41	1.50	1.14	1.45	1.34
1998	1.34	1.50	1.19	1.47	1.32
1999	1.26	1.52	1.12	1.48	1.36
2000	1.34	1.56	1.14	1.50	
2001	1.42	1.57	1.10	1.46	
2002	1.36	1.64	1.15		
2003	1.46	1.70	1.29		
2004		1.62	1.25		
2005					

Source: FERC Form 423.

Exhibit ____ (RS-11)

<u>Coal Week</u> September 23, 1996 re: Miller Plant

TRANSPORTATION

RAIL ACCESS DEBATE GOES PUBLIC; WCTA HEARS PROS AND CONS OR COMPETITION

The debate over "open access" to the nation's rail lines surfaced in a public forum Sept. 11 when the Western Fuels Assn.'s general manager squared off against Union Pacific senior vice president and Greg Swienton Burlington Northern Santa Fe's senior vice present for coal and agricultural commodities.

The public debate happened at the same time an unnamed working group of rail shippers met in the Washington area to develop a strategy to bring about open access to the nation's railroads. The group met the week of Sept. 9 and has plans to meet again. Sources would say only that the working group moved forward in its talks.

In Denver, Palmer, Peters and Swienton made up a panel at the fall meeting of the Western Coal Transportation Assn.

Palmer told *Coal Week* last week, "Obviously, we're very concerned with the whole question of competitive access. We are very active in promoting rail-on-rail competition." His thesis is that the railroads are monopolists and that rail mergers over the past two years will lower competition still more. "We'll be making a case before the Surface Transportation Board that the railroads are revenue adequate in any realistic sense of the word and that they should be subject to open competitions," Palmer said.

Pattern applies to rails

The case WFA and others plan to set before the STB is that open access has been applied to in telecommunications, natural gas and electric power, that there is obvious discrimination in rates by the railroads and that the railroads charge "outrageously high export rail rates." "If the STB won't do it, we'll have to go to Congress," Palmer said. "But I'm an optimist and I detect some signs that the STB is going to be receptive."

Peters and Swienton told WCTA that the railroads have already been deregulated by the Staggers Rail Act of 1980 and that Staggers created open access in the form of mandatory interchange.

Swienton said rail service and performance are vastly better than in 1980. "More importantly, we are delivering better service at prices that are significantly lower than they were at the time of deregulation. We've gone from being an industry with excess capacity ... to one that is capacity constrained in some areas .. from large-scale layoffs ... to one that has hired hundreds of train crews over the past three years ... from wide-scale bankruptcies .. to setting traffic volume and revenue records. And we have done this while also substantially improving our safety record."

Status Quo is working

The partnership of the western railroads and the western utilities is a great success, Swienton said. BNSF has put $2 billion in capital improvements in the Orin line in the Powder River Basin, he said. He refuted claims that the railroads are monopolies saying nearly two thirds on inter-city freight is made by other modes of transportation. "Monopolists, but nature, increase prices and restrict output," Swienton said. "Railroads and coal transportation, however, have experienced declining prices and market expansion.

Attacking the concept of open rail access, Swienton argued, "How many railroad owners do you think are going to continue to pour billions of dollars of capital improvements in their franchises so that a competitor can come in and take the best traffic? ... We all must remember that it was the rail industry's inability to engage in differential pricing and its inability to make the capital investments required that put the industry on the verge of collapse (before the Staggers Act.)"

Peters made many of the same arguments, but added others. "Mandatory trackage rights are not necessarily tied to improved service and will probably not result in lower prices to consumers," he said. "Mandatory trackage rights is not about benefiting consumers. Railroads cannot charge rates for coal transportation that are above their variable costs unless the demand for electric power will support such rates. What consumers do not pay railroads, they will pay mine owners and electric utility generators. There is no public benefit, only private gain or loss in such a revenue transfer," Peters said.

MARKETS

SOUTHERN MOVES ON PRB COAL; BUYS FOR SCHERER. ~~READIES MILLER~~ 1-3

The Southern Company has moved to firm up its position in the Powder River Basin, buying about 2 million t/y of PRB coal from Kennecott Energy for the jointly-owned Scherer plant and firming up plans to alter coal handling and precipitator equipment at Alabama Power's plant Miller units 1-3 to allow those units to switch to low-cost PRB products.

Few details were available, but an official confirmed that Kennecott has won the long-term business for Scherer at a nominal tonnage of about 2 million t/y of 8,800 Btu/lb., 0.2 percent sulfur coal from the Antelope mine. The contract will have wide latitude for actual deliveries, so the tonnage is only approximate, the official said. Coalfield sources believe that Kennecott offered prices on the low side of the current range of spot prices.

SCS has bids in hand on its solicitation for long-term supplies of Powder River Basin coal for Alabama Power's plant Miller, but it is not certain it will sign contracts, the official said. A contract with Jim Walter Resources will terminate Aug. 31, 1999 and Alabama Power has decided to switch Miller units 1-3 to PRB coals.

The long lead time on the Miller switch stems from the nature of a contract extension clause in Alabama Power's contract with Jim Walter, the official said. Under the agreement, JWR and SCS had to reach agreement on a method for reaching a new price for coal delivered after Sept. 1, 1999. An official said JWR and SCS conducted a series of meetings earlier this year, but the deadline for the extension passed without agreement. As a result, the contract will expire as of Aug. 31, 1999 and Alabama Power will switch Miller 1-3 to PRB coals. Unit 4 burns PRB coal.

Coalfield sources said Alabama Power had insisted that JWR compete on a delivered price basis with PRB coal and that JWR had insisted on competing with Alabama coals. At over $53/t delivered, JWR could not compete with the $19-$20/t delivered price of the Cyprus Amax product, the sources agreed.

Although Miller will not take a derate by switching to subbituminous coal, the official said it must upgrade coal handling facilities to move more of the lower-heat product to the boilers. The result will be more and faster conveyor belts and inerting equipment where required. Alabama Power also will upgrade precipitators.

The official said the switch at Miller will require Alabama Power to switch deliveries of contract coal from Drummond Co. among others to other power plants. Transportation considerations will keep PRB coal out of the other plants.

Exhibit ____ (RS-12)

2005-2006 Progress Energy PRB

Crystal River Units 4 and 5 Studies

REDACTED (Non-Responsive)

Background & 2005 Timeline

- Apr - During his tours of our operations, Mr. McGehee learned that some of our dock facilities were blending PRB with bituminous coals.
- Apr - PRB review requested by Mike Williams
- May 9 – SE issued PRB Technical Evaluation Report
- Initially focused on [redacted] Crystal River North.
  - **Narrowed to CRN via economics.**
  - [redacted]
- Jul – SE authorized to proceed with S&L CRN PRB cost study
- **Jul 27-28 Plant PRB Study Kickoff Meeting**
- Aug 22- Financial Evaluation Report of PRB use issued by SE
- Sep 19 - S&L PRB Coal Conversion Study draft completed.
- **Sep 27 – Follow-up Plant Meeting**
- Oct 14 – S&L Final Report Issued
- **Oct 24 – Discussion with POG, FGD, TS&CD & RFD**

Progress Energy

PRB Potential at CRN

Crystal River
Plant Update

April 27, 2006

Dan Donochod, Strategic Engineering
Rob Reynolds, Regulated Fuels

Progress Energy

CR 4 & 5 Emissions & Fuel Savings: 20% PRB Blend via IMT (2007-2010)

Units 4 & 5 Combined	SO2 reduction (tons/yr)	SO2 Savings*	Delivered Fuel Savings**	Total Savings*** (SO2*, Fuel Ash & LOI)
2007	1,345	$1.3M	**$14.3M**	$15.5M
2008	1,335	$1.2M	**$12.1M**	$13.2M
2009	-	-	**$11.0M**	$10.8M
2010	-	-	**$9.5M**	$9.4M
Total	2,680	$2.5M	**$47M**	**$48.9M**

**FGD's come on-line in 2009. Assume not able to sell credits '09-'10.*

***Does not include costs to retrofit for PRB use.*

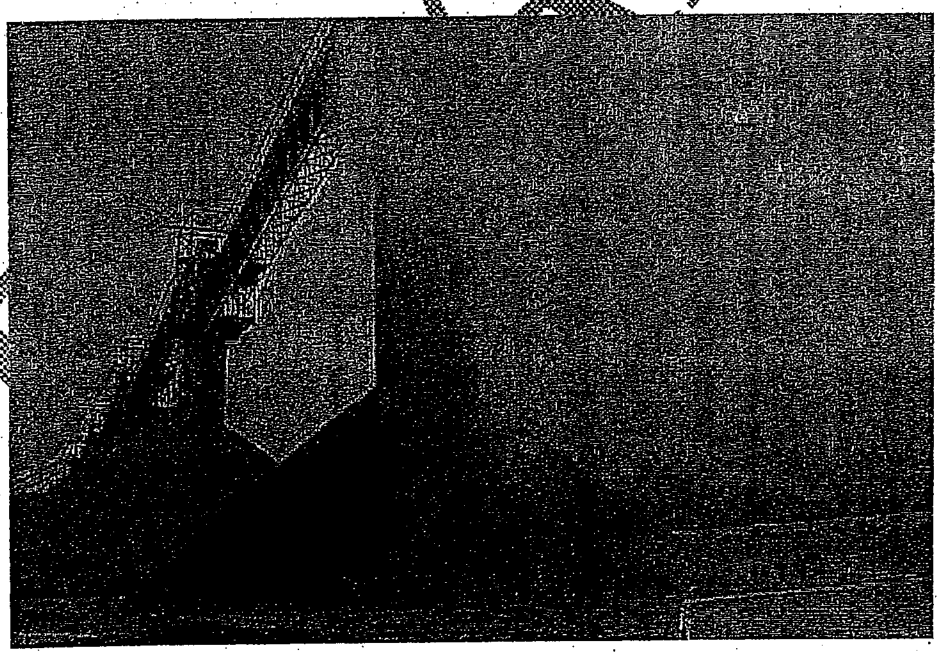
****Includes slight penalties for LOI increase and ash.*

Progress Energy

Progress Energy

Financial Evaluation of PRB Coal Use at Progress Energy's [redacted] [redacted] Crystal River 4 & 5 units

August 22, 2005



Prepared for: Regulated Fuels Department

Prepared by: Strategic Engineering Unit;
Technical Services & Construction Department

Progress Energy

Executive Summary

Previously Strategic Engineering evaluated the technical considerations of PRB use. This was assembled in a report dated May 9, 2005. The purpose of this report is to communicate financial impacts for fuel costs and SO_2 credits by using PRB under the following scenarios:

[redacted]

- 20% & 100% PRB use at Crystal River 4 & 5 units

While this report prepares the potential savings with PRB use, it does not address costs to use PRB (plant changes). However, those costs are currently being studied for Crystal River 4 & 5 by Sargent & Lundy (S&L). Their report, which evaluates three levels of PRB use, is expected by mid-September 2005.

Conclusions

Crystal River 4 & 5:

- **20% PRB preblended with river CAPP product (through the International Marine Terminal (IMT), a large port located near New Orleans) could provide $57MM in combined fuel savings and SO_2 credits over 2007-2008. FGD's are scheduled to be on-line in 2009. PRB use could continue with FGD's on-line if design accommodates.**
- **No economic benefit to convert units to 100% PRB under current price projections.**

[redacted]

Recommendations

Crystal River 4 & 5

- **Review S&L's costs using the PRB/CAPP blended product and then consider timeline for implementation. S&L report due mid-September 2005.**

PRB Potential at CRN

Plant Update

September 27, 2005

Progress Energy

CR 4 & 5 Emissions & Fuel Savings: 20% PRB Blend via IMT (2007-2010)

Units 4 & 5 Combined	SO2 reduction (tons/yr)	SO2 Savings*	Delivered Fuel Savings**	Total Savings*** (SO2*, Fuel, Ash & LOI)
2007	1,345	$1.3M	**$14.3M**	$15.5M
2008	1,335	$1.2M	**$12.1M**	$13.2M
2009	-	-	**$11.0M**	$10.8M
2010	-	-	**$9.5M**	$9.4M
Total	2,680	$2.5M	**$47M**	**$48.9M**

**FGD's come on-line in 2009. Assume not able to sell credits '09-'10.*

***Does not include costs to retrofit for PRB use. (+/-$4.4M including $1M sootblowers).*

****Includes slight penalties for LOI increase and ash.*

Progress Energy

CERTIFICATE OF ANALYSIS

COMPANY REQUESTING ANALYSIS:
Kanawha River Terminals

SAMPLE CHRONOLOGY	
DATE ANALYSED	June 23, 2005
LAB NUMBER	999865389
SAMPLE TAKEN BY	CLIENT

Blend Coal; Analysis 70% Appalachian Coal & 30% Powder River Basin Coal

	AS RECEIVED	DRY BASIS	M.A.F. BTU
PROXIMATE ANALYSIS			
% MOISTURE	13.52	N/A	N/A
%ASH	8.91	10.30	N/A
% VOLATILES	32.89	38.03	N/A
% FIXED CARBON	44.68	51.67	N/A
BTU	11117	12855	14331
% SULFUR	0.56	0.65	N/A
SULFUR FORMS			
% PYRITIC SULFUR	0.08	0.09	
% SULFATE SULFUR	0.24	0.28	
% ORGANIC SULFUR	0.24	0.28	
% TOTAL SULFUR	0.56	0.65	
T-250 TEMP. OF ASH		°F	
ASH FUSION	REDUCING		
INITIAL, °F	2440		
SOFTENING, °F	2500		
HEMMISPHERICAL, °F	2560		
FLUID, °F	2640		

	AS RECEIVED	DRY BASIS
ULTIMATE ANALYSIS		
% MOISTURE	13.52	N/A
% CARBON	61.16	70.72
% HYDROGEN	4.40	5.09
% NITROGEN	0.89	1.03
% CHLORINE	0.06	0.07
% SULFUR	0.56	0.65
% ASH	8.91	10.30
% OXYGEN (BY DIFF.)	10.50	12.14

ASH MINERAL ANALYSIS		%WT. IGNITED BASIS
PHOSPHOROUS PENTOXIDE	(P2O5)	0.51
SILICON DIOXIDE	(SiO2)	46.80
FERRIC OXIDE	(Fe2O3)	5.43
ALUMINUM TRIOXIDE	(Al2O3)	23.79
TITANIUM DIOXIDE	(TiO2)	1.67
CALCIUM OXIDE	(CaO)	8.97
MAGNESIUM OXIDE	(MgO)	1.74
SULFUR TRIOXIDE	(SO3)	4.08
POTASSIUM OXIDE	(K2O)	0.87
SODIUM OXIDE	(Na2O)	1.17
UNDETERMINED		4.97
HARDGROVE INDEX		48 DIMENSIONLESS

TRACE METALS	PPM AS RECEIVED WHOLE COAL BASIS
ANTIMONY (Sb)	
ARSENIC (As)	2.45
BARIUM (Ba)	
BERYLLIUM (Be)	
CADMIUM (Cd)	
COBALT (Co)	
COPPER (Cu)	
CHROMIUM (Cr)	
GOLD (Au)	
LEAD (Pb)	4.82
LITHIUM (Li)	
MANGANESE (Mn)	
MERCURY (Hg)	0.08
MOLYBDENUM (Mo)	
NICKEL (Ni)	
SELENIUM (Se)	
SILVER (Ag)	
THALLIUM (Tl)	
VANADIUM (V)	
ZINC (Zn)	

ID COMPONENTS	
Manganese Oxide	0.01
Barium Oxide	0.54
Strontium Oxide	0.35

FOULING FACTOR	
SLAGGING FACTOR	
CHLORINE	769
FLUORINE	30.41
BROMINE	

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-12)
Page 8 of 10

CERTIFICATE OF ANALYSIS

COMPANY REQUESTING ANALYSIS:	SAMPLE CHRONOLOGY	
Kanawha River Terminals	DATE ANALYSED	
	LAB NUMBER	
	SAMPLE TAKEN BY	

Appalachian Coal

PROXIMATE ANALYSIS	AS RECEIVED	DRY BASIS	M.A.F. BTU
% MOISTURE	7.97	N/A	N/A
%ASH	10.25	11.14	N/A
% VOLATILES	28.83	31.33	N/A
% FIXED CARBON	52.94	57.53	N/A
BTU	12239	13299	14966
% SULFUR	0.73	0.79	N/A

SULFUR FORMS	AS RECEIVED	DRY BASIS
% PYRITIC SULFUR	0.16	0.17
% SULFATE SULFUR	0.07	0.08
% ORGANIC SULFUR	0.50	0.54
% TOTAL SULFUR	0.73	0.32
T-250 TEMP. OF ASH		°F

ASH FUSION	REDUCING
INITIAL, °F	2700+
SOFTENING, °F	2700+
HEMMISPHERICAL, °F	2700+
FLUID, °F	2700+

ULTIMATE ANALYSIS	AS RECEIVED	DRY BASIS
% MOISTURE	7.97	N/A
% CARBON	65.14	70.79
% HYDROGEN	4.66	5.06
% NITROGEN	0.98	1.06
% CHLORINE	0.08	0.09
% SULFUR	0.73	0.79
% ASH	10.25	11.14
% OXYGEN (BY DIFF.)	10.19	11.07

ASH MINERAL ANALYSIS		%WT. IGNITED BASIS
PHOSPHOROUS PENTOXIDE	(P2O5)	0.43
SILICON DIOXIDE	(SiO2)	51.61
FERRIC OXIDE	(Fe2O3)	5.31
ALUMINUM TRIOXIDE	(Al2O3)	27.04
TITANIUM DIOXIDE	(TiO2)	1.84
CALCIUM OXIDE	(CaO)	3.99
MAGNESIUM OXIDE	(MgO)	0.83
SULFUR TRIOXIDE	(SO3)	0.93
POTASSIUM OXIDE	(K2O)	1.03
SODIUM OXIDE	(Na2O)	1.26
UNDETERMINED		4.76
HARDGROVE INDEX		46 DIMENSIONLESS

TRACE METALS	PPM AS RECEIVED WHOLE COAL BASIS
ANTIMONY (Sb)	
ARSENIC (As)	3.39
BARIUM (Ba)	
BERYLLIUM (Be)	
CADMIUM (Cd)	
COBALT (Co)	
COPPER (Cu)	
CHROMIUM (Cr)	
GOLD (Au)	
LEAD (Pb)	6.41
LITHIUM (Li)	
MANGANESE (Mn)	
MERCURY (Hg)	0.10
MOLYBDENUM (Mo)	
NICKEL (Ni)	
SELENIUM (Se)	
SILVER (Ag)	
THALLIUM (Tl)	
VANADIUM (V)	
ZINC (Zn)	

ID COMPONENTS	
Manganese Oxide	0.01
Barium Oxide	0.57
Strontium Oxide	0.39

FOULING FACTOR	
SLAGGING FACTOR	
CHLORINE	1026
FLUORINE	32.19
BROMINE	

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-12)
Page 9 of 10

PEF-FUEL-002695

CERTIFICATE OF ANALYSIS

COMPANY REQUESTING ANALYSIS:	SAMPLE CHRONOLOGY	
Kanawha River Terminals	DATE ANALYSED	
	LAB NUMBER	
	SAMPLE TAKEN BY	

Powder River Basin Coal

PROXIMATE ANALYSIS	AS RECEIVED	DRY BASIS	M.A.F. BTU
% MOISTURE	26.47	N/A	N/A
%ASH	6.12	8.32	N/A
% VOLATILES	39.47	53.68	N/A
% FIXED CARBON	27.94	38.00	N/A
BTU	8692	11821	12894
% SULFUR	0.24	0.32	N/A

SULFUR FORMS	AS RECEIVED	DRY BASIS
% PYRITIC SULFUR	0.01	0.02
% SULFATE SULFUR	0.17	0.23
% ORGANIC SULFUR	0.06	0.07
% TOTAL SULFUR	0.24	0.32
T-250 TEMP. OF ASH		°F

ASH FUSION	REDUCING
INITIAL, °F	2060
SOFTENING, °F	2100
HEMMISPHERICAL, °F	2170
FLUID, °F	2220

ULTIMATE ANALYSIS	AS RECEIVED	DRY BASIS
% MOISTURE	26.47	N/A
% CARBON	49.97	70.56
% HYDROGEN	3.67	5.18
% NITROGEN	0.69	0.97
% CHLORINE	0.01	0.01
% SULFUR	0.24	0.32
% ASH	6.12	8.32
% OXYGEN (BY DIFF.)	12.83	14.62

ASH MINERAL ANALYSIS		%WT. IGNITED BASIS
PHOSPHOROUS PENTOXIDE	(P_2O_5)	0.69
SILICON DIOXIDE	(SiO_2)	35.57
FERRIC OXIDE	(Fe_2O_3)	5.71
ALUMINUM TRIOXIDE	(Al_2O_3)	16.21
TITANIUM DIOXIDE	(TiO_2)	1.28
CALCIUM OXIDE	(CaO)	20.60
MAGNESIUM OXIDE	(MgO)	3.85
SULFUR TRIOXIDE	(SO_3)	11.43
POTASSIUM OXIDE	(K_2O)	0.49
SODIUM OXIDE	(Na_2O)	0.98
UNDETERMINED		2.45
HARDGROVE INDEX	52	UNITLESS

TRACE METALS	PPM AS RECEIVED WHOLE COAL BASIS
ANTIMONY (Sb)	
ARSENIC (As)	0.25
BARIUM (Ba)	
BERYLLIUM (Be)	
CADMIUM (Cd)	
COBALT (Co)	
COPPER (Cu)	
CHROMIUM (Cr)	
GOLD (Au)	
LEAD (Pb)	1.11
LITHIUM (Li)	
MANGANESE (Mn)	
MERCURY (Hg)	0.02
MOLYBDENUM (Mo)	-
NICKEL (Ni)	
SELENIUM (Se)	
SILVER (Ag)	
THALLIUM (Tl)	
VANADIUM (V)	
ZINC (Zn)	

ID COMPONENTS	
Manganese Oxide	0.01
Barium Oxide	0.47
Strontium Oxide	0.26

FOULING FACTOR	
SLAGGING FACTOR	
CHLORINE	170
FLUORINE	26.25
BROMINE	

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-12)
Page 10 of 10

PEF-FUEL-002696

Exhibit ____ (RS-13)

FPC Briquettes Letters and Related Permits

Florida Power CORPORATION

February 22, 1999

Mr. Al Linero, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Coal "Briquettes" Fuel

As you know from previous correspondence, Florida Power Corporation (FPC) has been approached by its fuel supplier, Electric Fuels Corporation concerning the possibility of burning "coal briquettes" at its Crystal River plant. The briquettes are produced from coal fines at the mines that currently supply the coal for Crystal River Units 1, 2, 4, and 5. Coal fines are combined under heat and pressure with a small amount of oil (maximum of 5% Bunker C oil) at the mine. The oil is the binding agent for the coal fines. Subjecting the coal fines to heat and pressure removes moisture and produces the coal briquettes, which are small chunks of coal that can be handled and burned with the regular coal supply.

The following table shows the average sulfur content of the coal supplies burned in Units 1 and 2, and in Units 4 and 5. The averages are based on daily coal samples averaged over the calendar year and have been reported in the Annual Operating Reports for these units.

	1996	1997	1998	Average
Units 1 and 2	1.03%	1.07%	1.05%	1.05%
Units 4 and 5	0.68%	0.67%	0.69%	0.68%

FPC would receive the briquettes in shipments blended with some of the regular coal supply. In order to ensure that the addition of coal briquettes does not result in an increase in emissions due to the sulfur content of the Bunker C oil, FPC is willing to commit to limiting the sulfur content of these shipments. The sulfur content, as averaged on an annual basis, of the shipments of briquettes combined with coal, will not exceed 1.05% for Units 1 and 2, and will not exceed 0.68% for Units 4 and 5.

Use of the briquettes as fuel is an environmentally beneficial way of utilizing the coal fines resulting from the mining process. If not used as fuel, the fines would otherwise be discarded. Limiting the sulfur content of the fuel to historical levels ensures that no emissions increase will result.

FPC requests that the DEP add "coal briquettes" to the list of fuels authorized to be burned in units 1, 2, 4, and 5, ~~subject to the sulfur~~ content limitation. This limit would apply to the annual average ~~sulfur~~ content of the shipments received of briquettes combined with coal. Please contact Mike Kennedy at (727) 826-4334 if you have any questions.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director, Environmental Services
FPC Responsible Official

Florida Power
CORPORATION

RECEIVED

MAR 17 1999

BUREAU OF
AIR REGULATION

March 15, 1999

Mr. Clair Fancy, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Re: Petroleum Coke Permitting

As you know, a final construction permit authorizing a blend of coal and petroleum coke to be burned in Florida Power Corporation's (FPC) Crystal River Units 1 and 2 was issued by the DEP on January 11, 1999. FPC requests that the conditions authorizing use of the blended fuel be incorporated into the Title V permit for these units.

In addition, the DEP is currently reviewing FPC's submittal to allow use of "coal briquettes" in Crystal River Units 1, 2, 4, and 5. FPC understands that approval is forthcoming, pending receipt of a $250 processing fee. Therefore, FPC also requests that the Title V permit also reflect this approval at the appropriate time.

Thank you for your consideration of these requests. Please contact Mike Kennedy at (727) 826-4334 if you have any questions.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director

Attachment E

Excerpt, Florida Department of Environmental Protection's Notice of Intent of Issue Air Construction Permit, dated May 25, 1999

Subject: Proposal of Florida Power Corporation to burn "Bituminous Coal Briquettes" at Crystal River

Attachment F

In the Matter of an
Application for Permit by:

Florida Power Corporation
3201 34th Street South
St. Petersburg, Florida 33711

DEP File No 0170004-006-AC
Crystal River Power Plant
Citrus County
Coal/Briquette Fuel Mixture

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft permit attached) for the proposed project, detailed in the application specified above and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, Florida Power Corporation, applied on March 24, 1999 to the Department for an air construction permit for its Crystal River Plantlocated west of U.S. Highway 19, north of Crystal River, south of the Cross State Barge Canal, Citrus County. The permit is to allow the combustion of a coal/briquette fuel mixture in Crystal River Units 1,2,4, and 5. The briquettes will be blended with some of the regular coal supply and Florida Power Corporation states the sulfur content of the coal/briquette fuel mixture, percent by weight and averaged on an annual basis, will not exceed the average sulfur content of the coal combusted in each unit averaged for the past three years. The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to allow the combustion and to restrict the sulfur content of the coal/briquette fuel.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

Florida Power Corporation
Crystal River Plant
Facility ID No.: 0170004
Citrus County

Initial Title V Air Operation Permit
FINAL Permit No.: 0170004-004-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-1344
Fax: 850/922-6979

Compliance Authority:
Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
004	Fossil Fuel Steam Generator, Unit 4, a dry bottom wall-fired unit, rated at 760 MW, 6665 MMBtu/hr, capable of burning bituminous coal, a bituminous coal and bituminous coal briquette mixture, and used oil, with number 2 fuel oil as a startup fuel, and natural gas as a startup and low-load flame stabilization fuel, with emissions exhausted through a 600 ft. stack.
003	Fossil Fuel Steam Generator, Unit 5, a dry bottom wall-fired unit, rated at 760 MW, 6665 MMBtu/hr, capable of burning bituminous coal, a bituminous coal and bituminous coal briquette mixture, and used oil, with number 2 fuel oil as a startup fuel, and natural gas as a startup and low-load flame stabilization fuel, with emissions exhausted through a 600 ft. stack.

Fossil Fuel Steam Generators, Units 4 and 5, are pulverized coal dry bottom boilers, wall-fired Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Combustion Engineering.

{Permitting Notes: These emissions units are regulated under Acid Rain, Phase I and II and Rule 62-210.300, F.A.C., Permits Required; 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; and, Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 4 began commercial operation in 1982. Fossil fuel fired steam generator Unit 5 began commercial operation in 1984.}

The following specific conditions apply to the emissions unit(s) listed above:

{Permitting note: In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

<u>Essential Potential to Emit (PTE) Parameters</u>

B.1. <u>Permitted Capacity</u>. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
004	6665	Bituminous Coal and Bituminous Coal /Bituminous Coal Briquette Mixture
003	6665	Bituminous Coal and Bituminous Coal /Bituminous Coal Briquette Mixture

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition I.11.
[Rule 62-297.310(2), F.A C.]

B.3. Methods of Operation. Fuels. The only fuel allowed to be burned is bituminous coal or bituminous coal and bituminous coal briquette mixture with the exception that number 2 fuel oil may be used as an ignitor fuel, and natural gas may be used as a startup and low-load flame stabilization fuel. Fuel oil shall not contain more than 0.73% sulfur by weight. These emissions units may also burn used oil in accordance with other conditions of this permit (see Subsection K).
[Rule 62-213 410, F.A.C.; and, PPSC PA 77-09 and modified conditions]

Emission Limitations and Standards

B.4. Pursuant to 40 CFR 60.42 Standard For Particulate Matter.

(a) No owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:
(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel.
(2) Exhibit greater than 20 percent opacity, six minute average, except for one six-minute period per hour of not more than 27 percent opacity.
[40 CFR 60.42(a)(1) & (2)]

B.5.a. Standard For Sulfur Dioxide.

(a) ~~No owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases~~ which contain sulfur dioxide in excess of:
(1) 340 nanograms per joule heat input (0.80 lb per million Btu), 24-hour average, derived from liquid fossil fuel.
(2) 520 nanograms per joule heat input (1.2 lb per million Btu), 24-hour average, derived from solid fossil fuel.
(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO2} = [y(340) + z(520)]/(y+z)$$

where:
PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,
y is the percentage of total heat input derived from liquid fossil fuel, and
z is the percentage of total heat input derived from solid fossil fuel.
(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.
[40 CFR 60.43(a), (b) and (c); and, PPSC PA 77-09]

Exhibit ____ (RS-14(a))

Synfuels to IMT for Crystal River Units 4 and 5

Summary Table

Exhibit ___
Page 1 of 1

Coal And Synfuels Sources Of CAPP Coal To IMT For Crystal River 4/5

Year	Total CAPP And Synfuel Tons To IMT	PEF/PFC Tons Of Coal And Synfuels To IMT	% Affiliate Tons Of CAPP/ Synfuel Coal
2000	2,172,600	1,153,700	53.1
2001	1,884,100	1,665,700	88.4
2002	1,774,500	1,762,200	99.3
2003	1,074,100	843,000	78.5
2004	980,700	739,400	75.4
2005	887,100	321,100	36.2

Exhibit ____ (RS-14(b))

Synfuels to IMT for Crystal River Units 4 and 5

PEF Synfuels Summary

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-14(b))
Page 1 of 1

Progress Energy Florida
Annual Synfuel Delivered to Crystal River

Synfuel Producer	Marketing Agent	2000 Tons	2000 %	2000 BTU's	2001 Tons	2001 %	2001 BTU's	2002 Tons	2002 %	2002 BTU's	2003 Tons	2003 %	2003 BTU's	2004 Tons	2004 %	2004 BTU's	2005 Tons	2005 %	2005 BTU's
lew River Synfuel LLC	Black Hawk Synfuel	962,435	75%	12,182	1,784,140	100%	12,191	859,001	54%	12,397	-	0%	-	-	0%	-	-	0%	-
	CR 1&2	94,823		12,229	3,594		12,336	-		-	-		-	-		-	-		-
	CR 4&5	867,612		12,177	1,780,546		12,191	859,001		12,397	-		-	-		-	-		-
Sandy River Synfuel LLC	(sold direct)	329,390	25%	12,268	-	0%	-	-	0%	-	-	0%	-	-	0%	-	-	0%	-
	CR 1&2	-		-	-		-	-		-	-		-	-		-	-		-
	CR 4&5	329,390		12,268	-		-	-		-	-		-	-		-	-		-
lew River Synfuel	Kanawha River Terminal**	-	0%	-	-	0%	-	501,204	32%	12,688	40,715	9%	12,456	-	0%	-	-	0%	-
alla Synfuel	CR 1&2	-		-	-		-	-		-	-		-	-		-	-		-
nperial Synfuel	CR 4&5	-		-	-		-	501,204		12,688	40,715		12,456	-		-	-		-
C Synfuel																			
C Synfuel	Riverside Synfuel	-	0%	-	-	0%	-	-	0%	-	20,223	4%	12,418	-	0%	-	-	0%	-
	CR 1&2	-		-	-		-	-		-	-		-	-		-	-		-
	CR 4&5	-		-	-		-	-		-	20,223		12,418	-		-	-		-
lew River Synfuel	Progress Fuels**	-	0%	-	-	0%	-	-	0%	-	-	0%	-	64,382	48%	12,478	-	0%	-
alla Synfuel	CR 1&2	-		-	-		-	-		-	-		-	-		-	-		-
mperial Synfuel	CR 4&5	-		-	-		-	-		-	-		-	64,382		12,478	-		-
alla Synfuel	Marmet Synfuel**	-	0%	-	-	0%	-	220,629	14%	13,127	394,997	87%	13,016	5,257	4%	12,892	-	0%	-
mperial Synfuel	CR 1&2	-		-	-		-	-		-	-		-	-		-	-		-
	CR 4&5	-		-	-		-	220,629		13,127	394,997		13,016	5,257		12,892	-		-
Jnknown	Central Coal Co.	-	0%	-	-	0%	-	-	0%	-	-	0%	-	65,786	49%	12,635	12,481	100%	12,221
	CR 1&2	-		-			-	-		-	-		-	-		-	-		-
	CR 4&5	-		-			-	-		-	-		-	65,786		12,635	12,481		12,221
	Total / Avg. BTU	1,291,825	100%	12,204	1,784,140	100%	12,191	1,580,834	100%	12,591	455,935	100%	12,939	135,425	100%	12,570	12,481	100%	12,221
	CR 1&2	94,823			3,594			-			-			-			-		
	CR 4&5	1,197,002			1,780,546			1,580,834			455,935			135,425			12,481		

** Marketing agent for multiple synfuel producers

Exhibit ____ (RS-14(c))

Synfuels to IMT for Crystal River Units 4 and 5

FPSC and FERC 423's

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-14(c))
Page 1 of 4

D. 423-2B

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE AND AS RECEIVED QUALITY

'o. February 2004

npany: Florida Power Corporation

Transfer Facility - IMT

4. Name, Title and Telephone Number of Contact Person Concerning Data Submitted on this Form
Donna M. Davis, Director - Regulatory & Adm. Services
(727) 824-6627

5. Signature of Official Submitting Report

Donna M. Davis, Director - Regulatory & Adm. Services

6. Date Completed: April 15, 2004

SPECIFIED CONFIDENTIAL

e	Supplier Name	Mine Location	Shipping Point	Transportation Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Rate ($/Ton)	Other Rail Charges ($/Ton)	River Barge Rate ($/Ton)	Trans-loading Rate ($/Ton)	Ocean Barge Rate ($/Ton)	Other Water Charges ($/Ton)	Other Related Charges ($/Ton)	Transportation Charges ($/Ton)	F.O.B. Plant Price ($/Ton)
)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
	Guasare Coal Sales Corp.	50 , IM , 999	Maracaibo, VZ	GB	50,502	$39.94	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$5.05	$44.99
	Central Coal Co.	08 , WV , 39	Kanawha,Wv	B	10,574	$38.75	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$19.61	$58.36
	Central Coal Co.	08 , WV , 39	Kanawha,Wv	B	7,351	$39.50	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$19.61	$59.11
	Kanawha River Terminal	08 , WV , 39	Kanawha,Wv	B	1,701	$32.25	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$19.61	$51.86
	Progress Fuels Corporation	08 , WV , 39	Kanawha,Wv	B	32,326	$33.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$19.61	$52.61
	Progress Fuels Corporation	08 , WV , 39	Ceredo,Wv	B	15,252	$40.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$19.61	$59.61
	Progress Fuels Corporation	08 , WV , 39	Kanawha,Wv	B	5,221	$31.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$19.61	$50.61
	Progress Fuels Corporation	08 , WV , 39	Kanawha,Wv	B	17,737	$31.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$19.61	$50.61
	Progress Fuels Corporation	08 , WV , 39	Kanawha,Wv	B	12,378	$31.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$19.61	$50.61

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

This report is mandatory under the Federal Power Act. Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature

Form Approved
OMB No. 1902-0024
Expires: 01/31/2003

Check if Resubmission [ ]

1. Company-Plant Code	2. Name of Reporting Company	3. Month and Year of Report	4. Page Number
6455 - 9988	Florida Power Corp	Feb, 2004	1 OF 1

5. Plant Name	6. Name and Title of Contact Person
Intern'l Marine TF	Delmar J. Clark., Senior Financial Analyst - Regulatory

7. Address of Contact Person	8. Contact Phone # (727) 824-6616
One Progress Plaza St. Petersburg, Fl 33701	E-mail Address del.clark@progressfuels.com

9. Name and Title of Certifying Official	10. Signature of Certifying Offical	11. Date
Delmar J. Clark Jr., Senior Financial Analyst - Regulatory		04/24/2004

	PURCHASES		COAL MINES ONLY				SOURCE DATA		QUALITY (AS RECEIVED)			
				LOCATION								
Line No.	Type (Use code)	Expiration date (If contract Expires Within 2 yrs.) (mmddyy)	Fuel Type (Use code)	Type (Use code)	Coal District No.	State Abbrev.	For coal, enter name of mine or broker from which coal originated or was purchased For oil, enter name of supplier, refinery and if applicable, port of entry. For gas, enter name of supplier, popeline or distributor and, if applicable, port of entry.	Quantity Received (Units) Coal: 1,000 tons Oil: 1,000 barrels Gas: 1,000 MMBtu	Btu Content (Average of: Coal, Btu per lb; Oil, But per gal; Gas,Btu per cu.ft)	Sulfur Content (To nearest 0.01%)	Ash Content (To nearest 0.1%	FOB Purchase Price (In cents per million Btu to nearest 0.1 cent)
	(a)	(b)	(c)	(d)	(e)	(f)	(h)	(i)	(j)	(k)	(l)	(m)

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	County No. (g)	(h)	(i)	(j)	(k)	(l)	(m)
1	S	04/26/2004	BIT	U	50	50	999	Paso Diablo	50.50	12,919.00	0.72 %	6.88 %	175.730
2	S	04/26/2004	BIT	U/S	8	8	0	Winifrede Dock	10.57	12,612.00	0.74 %	10.12 %	243.170
3	S	04/26/2004	BIT	U/S	8	8	0	Kanawha River Terminal	7.35	12,749.00	0.60 %	8.89 %	246.290
4	S	04/26/2004	BIT	U/S	8	8	0	Kanawha River Terminal	1.70	12,339.00	0.63 %	13.23 %	216.080
5	S	04/26/2004	BIT	U/S	8	8	0	Kanawha River Terminal	32.32	12,369.00	0.58 %	11.60 %	210.440
6	S	04/26/2004	BIT	U	8	8	0	Ceredo Dock	15.25	12,449.00	0.64 %	10.48 %	238.440
7	S	04/26/2004	BIT	U/S	8	8	0	Kanawha River Terminal	5.22	12,486.00	0.59 %	10.02 %	202.440
8	S	04/26/2004	BIT	U/S	8	8	0	Kanawha River Terminal	17.73	12,526.00	0.63 %	9.56 %	202.440
9	S	04/26/2004	BIT	U/S	8	8	0	Kanawha River Terminal	12.37	12,497.00	0.65 %	9.36 %	202.440
10													

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __(RS-14(c))
Page 2 of 4

FERC 423 COAL SHIPMENTS BY UTILITY THROUGH DECEMBER 2002

S	CEXP	Supplier	Company	Division	Coal Mine	S/U	County	St	kTons	Btu/lb	Sulfur	Ash	SO2	$/Ton	C/MMBtu
		Quaker Coal	Quaker Coal	Damron Fork	SIDEWINDER	B	Pike	EK	38.9	12,543	0.70	10.53	1.12	51.02	203.38
	200211	Quaker Coal	Quaker Coal	Damron Fork	Sidewinder	B	Pike	EK	38.9	12,573	0.71	10.69	1.13	51.16	203.44
		Quaker Coal	Quaker Coal	Damron Fork	SIDEWINDER	U	Pike	EK	39.7	12,496	0.68	10.31	1.09	50.32	201.34
	200301	Quaker Coal	Quaker Coal	Damron Fork	Sidewinder	B	Pike	EK	29.8	12,575	0.68	10.03	1.08	54.77	217.77
		Massey	Massey	Rum Creek	HUTCHINSON	S	Logan	SW	9.9	12,157	0.71	13.18	1.17	54.88	225.71
	200211	Massey	Massey	Rum Creek	Hutchinson	S	Logan	SW	9.9	12,827	0.64	8.42	1.00	47.50	185.16
	200207	Massey	Massey	Rum Creek	Hutchinson	S	Logan	SW	19.8	12,496	0.71	10.37	1.14	60.20	240.88
	200212	Peabody	Peabody	Big Mountain	Licksiding	U	Boone	SW	10.3	12,537	0.70	10.86	1.12	55.68	222.06
	200211	Peabody	Peabody	Big Mountain	Licksiding	U	Boone	SW	10.4	12,732	0.72	10.46	1.13	56.62	222.35
		Peabody	Peabody	Rocklick	ROCKLICK (LICKSIDING)	U	Boone	SW	20.4	12,855	0.77	10.04	1.20	57.45	223.45
tal		Crystal River 4-5							1,088.8	12,570	0.69	9.97	1.09	56.13	223.27
IMT Transfer 4-5															
C	200210	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	36.2	12,474	0.70	10.61	1.12	57.03	228.60
C	200204	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	42.5	12,475	0.66	9.98	1.06	57.04	228.62
C	200204	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	S	Kanawha	SW	32.5	13,073	0.68	6.42	1.04	60.48	231.32
C	200208	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	43.0	12,265	1.00	12.00	1.63	56.08	228.62
C	200209	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	41.6	12,245	0.65	12.04	1.06	55.98	228.58
C	200211	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	35.1	12,307	0.69	11.60	1.12	56.27	228.61
C	200302	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	45.4	12,385	0.67	10.43	1.07	56.63	228.61
C	200212	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	42.5	12,518	0.68	9.90	1.09	57.23	228.59
C	200301	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	48.4	12,530	0.66	10.19	1.05	57.29	228.60
C	200211	Glencore	Glencore	Guasare	Guasare Coal Sales Corp.	U	Venezuela	IM	61.0	12,881	0.70	6.37	1.09	55.12	213.96
C	200212	Glencore	Glencore	Guasare	Guasare Coal Sales Corp.	U	Venezuela	IM	58.8	12,799	0.68	6.52	1.06	54.77	213.96
C	200212	Inter American Coal	Inter American Coal	Paso Diablo	Paso Diablo	U	Venezuela	IM	110.8	12,849	0.75	6.28	1.16	64.51	251.02
C	200312	Kanawha River Term	Kanawha River Term	Kanawha County	KANAWHA RIVER TERMINALS	S	Kanawha	SW	36.3	13,080	0.67	6.37	1.02	60.52	231.35
C	200312	Kanawha River Termin	Kanawha River Termin	Kanawha County	Kanawha River Terminals	S	Kanawha	SW	33.[illegible]	13,127	0.72	6.34	1.10	60.73	231.32
C	200107	Pen Coal	Pen Coal	Kiah Creek	KIAH CREEK		Wayne	SW	12.3	12,290	0.67	10.00	1.09	49.62	201.86
S	200210	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	7.0	12,517	0.71	10.58	1.14	65.84	262.99
S	200301	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	10.7	12,287	0.68	11.51	1.11	64.91	264.13
S	200209	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	8.8	12,173	0.66	11.95	1.08	64.50	264.91
S	200206	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	27.2	12,339	0.67	11.09	1.08	65.11	263.86
S	200208	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	8.0	12,208	1.00	12.00	1.64	64.61	264.60
S	200211	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	6.7	12,460	0.67	11.01	1.07	65.48	262.75
S		Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	BLACK HAWK SYNFUEL, LLC	B	Kanawha	SW	265.0	12,490	0.67	9.84	1.08	61.56	246.42
S	200212	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	6.8	12,391	0.69	10.19	1.11	65.16	262.92
S	200204	Black Hawk Synfuel L	Black Hawk Synfuel L	Synfuel	Black Hawk Synfuel, LLC	B	Kanawha	SW	8.8	13,233	0.69	6.26	1.04	70.15	265.06
S	200302	Drummond	Drummond	Mina Pribbenow	Puerto Drummond	B	Colombia	IM	1.4	12,052	0.65	5.91	1.08	54.88	227.68
S		Inter American Coal	Inter American Coal	Paso Diablo	PASO DIABLO	U	Venezuela	IM	47.9	12,837	0.70	5.70	1.09	64.45	251.03
S	200302	Kanawha River Term	Kanawha River Term	Kanawha County	Kanawha River Terminal	B	Kanawha	SW	59.4	12,724	0.67	8.63	1.05	58.63	230.41
S		Kanawha River Term	Kanawha River Term	Kanawha County	KANAWHA RIVER TERMINALS	S	Kanawha	SW	72.4	12,833	0.67	7.82	1.04	59.59	232.16
S	200209	Kanawha River Termin	Kanawha River Termin	Kanawha County	Kanawha River Terminal	B	Kanawha	SW	56.1	12,284	0.67	11.69	1.09	48.61	197.86
S	200208	Kanawha River Termin	Kanawha River Termin	Kanawha County	Kanawha River Terminal	B	Kanawha	SW	40.0	12,267	1.00	11.00	1.63	48.54	197.85
S	200301	Kanawha River Termin	Kanawha River Termin	Kanawha County	Kanawha River Terminal	B	Kanawha	SW	38.2	12,948	0.70	6.77	1.08	51.23	197.83
S	200210	Kanawha River Termin	Kanawha River Termin	Kanawha County	Kanawha River Terminal	B	Kanawha	SW	53.8	12,554	0.69	10.19	1.10	49.67	197.83
S	200211	Kanawha River Termin	Kanawha River Termin	Kanawha County	Kanawha River Terminal	B	Kanawha	SW	66.7	12,583	0.69	9.55	1.10	49.79	197.83

C/S	CEXP	Supplier	Company	Division	Coal Mine	S/U	County	St	kTons	Btu/lb	Sulfur	Ash	SO2	$/Ton	C/MMBtu
S	200212	Kanawha River Termin	Kanawha River Termin	Kanawha County	Kanawha River Terminal	B	Kanawha	SW	47.6	12,694	0.70	8.32	1.11	50.23	197.82
S	200207	Marmet Synfuel	Marmet Synfuel	Synfuel	Marmet Synfuel, LLC	S	Kanawha	SW	5.2	13,281	0.69	6.51	1.04	61.45	231.35
S	200302	Marmet Synfuel	Marmet Synfuel	Synfuel	Marmet Synfuel, LLC	B	Kanawha	SW	29.1	12,996	0.69	5.95	1.06	60.13	231.34
S	200208	Marmet Synfuel	Marmet Synfuel	Synfuel	Marmet Synfuel, LLC	S	Kanawha	SW	33.0	13,197	1.00	6.00	1.52	61.06	231.34
S	200211	Marmet Synfuel	Marmet Synfuel	Synfuel	Marmet Synfuel, LLC	B	Kanawha	SW	35.5	13,044	0.73	7.68	1.12	60.35	231.33
S	200301	Marmet Synfuel	Marmet Synfuel	Synfuel	Marmet Synfuel, LLC	B	Kanawha	SW	29.5	13,083	0.73	6.02	1.12	60.53	231.33
S	200212	Marmet Synfuel	Marmet Synfuel	Synfuel	Marmet Synfuel, LLC	B	Kanawha	SW	29.4	13,027	0.71	6.65	1.09	60.27	231.33
S	200209	Marmet Synfuel	Marmet Synfuel	Synfuel	Marmet Synfuel, LLC	S	Kanawha	SW	26.1	13,280	0.68	6.38	1.02	61.44	231.33
S	200210	Marmet Synfuel	Marmet Synfuel	Synfuel	Marmet Synfuel, LLC	B	Kanawha	SW	37.8	13,252	0.71	6.24	1.07	61.31	231.32
S	200207	New River Synfuels	New River Synfuels	Synfuel	New River Synfuel, LLC	B	Kanawha	SW	64.5	12,506	0.67	9.83	1.07	40.18	160.64
S	200206	New River Synfuels	New River Synfuels	Synfuel	New River Synfuel, LLC	B	Kanawha	SW	55.8	12,344	0.69	10.92	1.12	39.66	160.64
S		New River Synfuels	New River Synfuels	Synfuel	NEW RIVER SYNFUEL, LLC	B	Kanawha	SW	170.8	12,238	0.66	11.02	1.08	40.04	163.59
S	200208	New River Synfuels	New River Synfuels	Synfuel	New River Synfuel, LLC	B	Kanawha	SW	25.0	12,640	1.00	10.00	1.58	40.61	160.64
Total	IMT Transfer 4-5								2,054.4	12,624	0.71	9.00	1.12	55.34	219.18
Total	Florida Power								4,826.5	12,625	0.83	9.24	1.32	55.43	219.53
Fremont, NE				Last Reporting Month: 12 2002											
Lon Wright															
C		Arch	Arch	Black Thunder	BLACK THUNDER	S	Campbell	PY	109.9	8,752	0.29	5.73	0.66	20.09	114.76
C		Peabody	Peabody	NARC	PEABODY	S	Campbell	PY	179.7	8,877	0.20	4.31	0.45	19.17	107.97
Total	Lon Wright								289.6	8,829	0.23	4.85	0.52	19.52	110.53
Total	Fremont, NE								289.6	8,829	0.23	4.85	0.52	19.52	110.53
Gainesville, FL				Last Reporting Month: 12 2002											
Deerhaven															
C	200312	AEP Coal	AEP Coal	Pike County	AEP COAL CO. SIDEWINDER	U	Pike	EK	403.9	12,951	0.69	7.28	1.06	51.78	199.92
C	200206	Jim Walter	Jim Walter	Blue Creek 5	JIM WALTER RESOURCES (BLUE CREEK)	U	Tuscaloosa	AL	9.2	12,678	0.65	10.47	1.03	46.43	183.11
C	200212	Massey	Massey	Clay County	MASSEY COAL CO.	U	Clay	EK	28.0	13,124	0.65	8.90	0.99	54.04	205.88
C	200212	Massey	Massey	Elk Run	MASSEY COAL CO. ASHLEY KAY	U	Boone	SW	141.3	12,934	0.67	8.85	1.04	54.14	209.32
C	200206	Massey	Massey	Harlan County	MASSEY COAL CO. (BROOKSIDE)	U	Harlan	EK	155.6	12,972	0.65	7.97	1.00	54.37	209.57
C	200206	Pittston	Pittston	Moss 3	PITTSTON COAL SALES CORP.	U	Dickenson	VA	8.8	13,824	0.71	8.23	1.03	55.21	199.69
Total	Deerhaven								746.8	12,965	0.68	7.83	1.04	52.83	203.72
Total	Gainesville, FL								746.8	12,965	0.68	7.83	1.04	52.83	203.72
Grand Haven L&P				Last Reporting Month: 11 2002											
Sims															
S		AMCI	AMCI	Greene County	TANOMA	B	Armstrong	PA	63.7	12,325	2.23	11.76	3.62	36.77	149.16
S		RAG Coal	RAG Coal	Emerald	EMERALD	U	Greene	PA	79.8	13,163	2.92	7.82	4.44	40.48	153.77
S		Unknown	Unknown	Knox County	VIM	U	Knox	IN	3.3	9,682	0.60	16.59	1.24	25.61	132.24
Total	Sims								146.8	12,721	2.57	9.72	4.04	38.54	151.46
Total	Grand Haven L&P								146.8	12,721	2.57	9.72	4.04	38.54	151.46
Grand Island Utilities				Last Reporting Month: 12 2002											
Platte															
NC	200212	Arch	Arch	Black Thunder	BLACK THUNDER MINE, THUNDER BASIN COAL	S	Campbell	PY	360.0	8,777	0.30	5.52	0.67	12.79	72.88
Total	Platte								360.0	8,777	0.30	5.52	0.67	12.79	72.88
Total	Grand Island Utilities								360.0	8,777	0.30	5.52	0.67	12.79	72.88

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-14(c))
Page 4 of 4

Exhibit ____ (RS-15)

Crystal River Units 4 and 5 Sources to IMT: 1997-2005

Exhibit ___ (RS-15)
Page 1 of 1

Crystal River 4/5 Sources To IMT: 1997-2005

Year	000 Tons Total	IMT Non-Affiliated CAPP Coal	(%)	Coal-Synfuels/PEF	(%)	Imports	(%)	Western Colo/Wyo	(%)
1997	2,028.0	1,603.4	(79)	424.6	(21)	0.0			
1998	2,054.7	1,496.4	(73)	478.5	(23)	79.8	(4)		
1999	1,976.7	1,572.7	(80)	304.6	(15)	99.4	(5)		
2000	2,172.6	1,018.9	(47)	1,153.7	(53)	0.0			
2001	2,402.0	219.2	(9)	1,665.7	(69)	498.1	(21)	19.8	(1)
2002	2,054.4	12.3	(0)	1,762.2	(86)	279.9	(14)		
2003	1,532.7	231.1	(15)	843.0	(55)	458.6	(30)		
2004	1,940.5	241.3	(13)	739.4	(38)	933.6	(48)	26.2	(1)
2005	1,703.3	566.0	(33)	321.1	(19)	816.2	(48)		

Exhibit ____ (RS-16)

Synfuels Documents Progress Energy's U-9C-3

Dated September 30, 2001

Progress Energy Inc · U-9C-3 · For 9/30/01

Filed On 12/14/01 · SEC File 74-00051 · Accession Number 950168-1-501405

As Of	Filer	Filing	As/For/On	Docs:Pgs	Issuer	Agent
12/14/01	Progress Energy Inc	U-9C-3	9/30/01	1:7		Donne

Quarterly Report of an Energy or Gas-Related Company : Form U-9C-3
Filing Table of Contents

Document/Exhibit	Description	Pages	Size
1: U-9C-3	Quarterly Report of an Energy or Gas-Related Company	7	33K

Document Table of Contents

Page *(sequential)* *(alphabetic)* Top

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 1 of 49

- Item 5 -. Other Investments*
- Item 6 -. Financial Statements

- Other Investments*
- Summary of Aggregate Investment

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM U-9C-3

QUARTERLY REPORT

FOR THE QUARTER ENDED September 30, 2001

Filed Pursuant to Rule 58 of the Public Utility Holding Company Act of 1935

PROGRESS ENERGY, INC.
410 S. Wilmington Street
Raleigh, NC 27602

[Download Table]

Contents	*Page*
ITEM 1 - Organization Chart	2
ITEM 2 - Issuances and Renewals of Securities and Capital Contributions	3
ITEM 3 - Associate Transactions	3
ITEM 4 - Summary of Aggregate Investment	6
ITEM 5 - Other Investments	6
ITEM 6 - Financial Statements and Exhibits	7

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 3 of 49

ITEM 1 - ORGANIZATION CHART

Name of Reporting Company	Energy or Gas Related	State of Organization	Percentage of Voting Securities Held	Natur
Progress Ventures, Inc.	Energy	NC		
CPL Synfuels LLC	Energy	NC	100	Synthetic
Solid Fuel LLC	Energy	DE	90	Synthetic
Sandy River Synfuel LLC	Energy	DE	90	Synthetic
Colona Synfuel LLLP	Energy	DE	17	Synthetic
Strategic Resource Solutions Corp.	Energy	NC	100	Energy Ser
SRS Engineering Corp.	Energy	NC	100	Energy Eng
Spectrum Controls, Inc.	Energy	NC	100	Energy Con
Electric Fuels Corporation	Energy	FL	100	Procuremen Transporta
EFC Synfuel LLC	Energy	DE	100	Holding Co
Ceredo Synfuel LLC	Energy	DE	99	Synthetic
Sandy River Synfuel LLC	Energy	DE	9	Synthetic
Solid Energy LLC	Energy	DE	99	Synthetic
Solid Fuel LLC	Energy	DE	9	Synthetic
Kentucky May Coal Company, Inc.	Energy	VA	100	Coal Mine
Cincinnati Bulk Terminals, Inc.	Energy	DE	100	Coal and B Terminal
Kanawha River Terminals, Inc.	Energy	FL	100	Coal and B Terminal
Black Hawk Synfuel, LLC	Energy	DE	100	Synthetic
New River Synfuel LLC	Energy	CO	10	Synthetic
Ceredo Liquid Terminal LLC	Energy	DE	100	Emulsion P
Coal Recovery V, LLC	Energy	MO	25	Synthetic
Colona Newco, LLC	Energy	DE	100	Holding Co
Colona SynFuel Limited Partnership, LLLP	Energy	DE	20.1	Synthetic
Colona Sub No. 2, LLC	Energy	DE	100	Synthetic
Colona Synfuel Limited Partnership, LLLP	Energy	DE	1	Synthetic
Colona Synfuel Limited Partnership, LLLP	Energy	DE	61.9	Synthetic
Progress Materials, Inc.	Energy	FL	100	Manufactur

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 4 of 49

Progress Synfuel Holdings, Inc.	Energy	DE	100	Holding Co
Ceredo Synfuel LLC	Energy	DE	1	Synthetic
Sandy River Synfuel LLC	Energy	DE	1	Synthetic
Solid Energy LLC	Energy	DE	1	Synthetic
Solid Fuel LLC	Energy	DE	1	Synthetic
Utech Venture Capital Corporation	Energy	DE	9.76	Investment Electrotec
Utech Climate Challenge Fund	Energy	DE	9.8	Investment Electrotec

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No.__ (RS-16)
Page 5 of 49

[Enlarge/Download Table]

ITEM 2 - ISSUANCES AND RENEWALS OF SECURITIES AND CAPITAL CONTRIBUTION

Contribution Date	**Company Making Contribution**	**Company Receiving Contribution**	**Contribution Amount**
07/24/2001	EFC Synfuel, LLC	Solid Fuel, LLC	602,376.55
07/24/2001	Progress Synfuel Holdings, Inc.	Solid Fuel, LLC	66,930.73
07/30/2001	CPL Synfuels, LLC	Solid Fuel, LLC	6,023,765.49
08/28/2001	EFC Synfuel, LLC	Solid Fuel, LLC	428,741.54
08/28/2001	Progress Synfuel Holdings, Inc.	Solid Fuel, LLC	47,637.95
08/30/2001	CPL Synfuels, LLC	Solid Fuel, LLC	4,287,415.42
07/24/2001	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	84,502.86
07/24/2001	EFC Synfuel, LLC	Sandy River Synfuel, LLC	760,525.69
08/31/2001	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	58,193.51
08/31/2001	EFC Synfuel, LLC	Sandy River Synfuel, LLC	523,741.63
09/26/2001	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	12,043.25
09/26/2001	EFC Synfuel, LLC	Sandy River Synfuel, LLC	108,389.28
07/30/2001	CPL Synfuels, LLC	Sandy River Synfuel, LLC	7,605,256.92
08/30/2001	CPL Synfuels, LLC	Sandy River Synfuel, LLC	5,237,416.29
09/28/2001	CPL Synfuels, LLC	Sandy River Synfuel, LLC	1,083,892.73

Dividend Date	Company Making Dividend	Company Receiving Dividend	Dividend Amount

None to report for this quarter.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No.__ (RS-16)
Page 6 of 49

[Enlarge/Download Table]

ITEM 3. ASSOCIATE TRANSACTIONS

Part I - Transactions Performed by Reporting Companies on Behalf of Associate Companies

Reporting Company Rendering Services	*Associate Company Receiving Services*	*Types of Services Rendered*	*Direct Costs Charged*	*Indirect Costs Charged*	*Cost Capit*
SRS	CP&L	Energy Management	1,401,085		
Sandy River, LLC	Cincinnati Bulk Terminal, Inc.	Coal sales	568,099		
	Kentucky Coal Terminal, Inc.	Coal sales	8		
	Colona Synfuel, LLC	Coal sales	(437,591)		
Electric Fuels Corporation	Florida Power	Coal Sales	61,594,799		
Electric Fuels Corporation	Kanawha River Terminals, Inc	Coal Sales	5,110,756		
Electric Fuels Corporation	Florida Progress	Admin Services	2,264		
Electric Fuels Corporation	Florida Power	Admin Services	7,833		
Electric Fuels Corporation	Progress Energy Corporation	Admin Services	1,408		
Electric Fuels Corporation	CP & L	Admin Services	137,840		
Electric Fuels Corporation	Progress Land	Admin Services	35,987		
Electric Fuels Corporation	Little Black Mountain Coal Reserves Inc.	Admin Services	7,343		
Electric Fuels Corporation	Homeland Coal Company, Inc.	Admin Services	30,451		
Electric Fuels Corporation	Awayland Coal Company, Inc.	Admin Services	29,690		
Electric Fuels Corporation	Powell Mountain Joint Venture	Admin Services	277,926		
Electric Fuels Corporation	Powell Mountain Coal Company	Admin Services	316,470		

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 7 of 49

Electric Fuels Corporation	Murphy Land Company	Admin Services	3,559
Electric Fuels Corporation	Mesa Hydrocarbons, Inc.	Admin Services	6,487
Electric Fuels Corporation	Progress Synfuel Holdings, Inc	Admin Services	3,569
Electric Fuels Corporation	EFC Synfuel, LLC	Admin Services	185,963
Electric Fuels Corporation	Ceredo Synfuel, LLC	Admin Service	69,430
Electric Fuels Corporation	Marine River Terminals	Admin Services	5,915

4

[Enlarge/Download Table]

Electric Fuels Corporation	Progress Rail Services Corporation	Admin Services	1,325,772	1,325,772
Electric Fuels Corporation	Progress Materials, Inc.	Admin Services	413,550	413,550
Electric Fuels Corporation	Kentucky May Coal Company, Inc.	Admin Services	467,706	467,706
Electric Fuels Corporation	Diamond May Coal Company	Admin Services	279,533	279,533
Electric Fuels Corporation	Kentucky May Mining Company	Admin Services	227,736	227,736
Electric Fuels Corporation	Cincinnati Bulk Terminals, Inc.	Admin Services	167,097	167,097
Electric Fuels Corporation	Kanawha River Terminals, Inc.	Admin Services	956,718	956,718
Electric Fuels Corporation	Colona	Admin Services	114,633	114,633
Electric Fuels Corporation	Black Hawk	Admin Services	154,701	154,701
Electric Fuels Corporation	Ceredo Liquid Terminals, LLC	Admin Services	67,751	67,751
Colona Synfuel, LLC	Kentucky Coal Terminal, Inc.	Coal Sales	100,967	100,967

[Enlarge/Download Table]

ITEM 3.

Part II - Transactions Performed by Associate Companies on Behalf of Reporting Companies

Associate Company Rendering Services	Reporting Company Receiving Services	Types of Services Rendered	Direct Costs Charged	Indirect Costs Charged	Cost o Capita
Progress Energy Services	SRS	Admin Services	376,520	411,857	
CP&L	SRS	Admin Services	166,531		

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 9 of 49

Powell Mountain Joint venture	Solid Fuel, LLC	Admin Services	19,029,026
Florida Power	Electric Fuels Corporation	Admin Services	473,248
Progress Energy, Inc.	Electric Fuels Corporation	Admin Services	47,992
Progress Energy Service Corporation	Electric Fuels Corporation	Admin Services	739,056
Progress Ventures	Electric Fuels Corporation	Admin Services	567,499
Powell Mountain Joint Venture	Electric Fuels Corporation	Coal Sales	3,617,320
Memco Barge Lines, Inc.	Electric Fuels Corporation	Barge Transportation	5,864,049
Kanawha River Terminals, Inc.	Electric Fuels Corporation	Coal Sales	1,365,712
Black Hawk Synfuel, LLC	Electric Fuels Corporation	Coal Sales	11,797,883
Electric Fuels Corporation	Sandy River Synfuels, LLC	Coal Sales	8
Black Hawk Synfuel, LLC	Sandy River Synfuels, LLC	Coal Sales	5,033

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 10 of 49

U-9C-3 *6th Page of 7* TOC 1st Previous Next Bottom Just 6th

[Enlarge/Download Table]

Kentucky May Coal Company, Inc.	Sandy River Synfuels, LLC	Admin Services	7,500,935	7,500,935
Kentucky Coal Terminal, Inc	Colona Synfuel, LLC	Coal Sales	25,525,922	25,525,922
Kentucky Coal Terminal, Inc	Colona Synfuel, LLC	Land Rent	6,000	6,000
Black Hawk Synfuel, LLC	Colona Synfuel, LLC	Coal Sales	780,645	780,645
Ceredo Liquid Terminal	Colona Synfuel, LLC	Admin Services	2,519,158	2,519,158

[Enlarge/Download Table]

ITEM 4 - SUMMARY OF AGGREGATE INVESTMENT

Investments in energy-related companies:	(000's)	
Total consolidated capitalization as of 9/30/01.	$16,306,485	Line 1
Total capitalization multiplied by 15% (line 1 multiplied by 0.15)	$2,445,973	Line 2
Greater of $50 million or line 2	$2,445,973	Line 3
Total current aggregate investment: (categorized by major line of energy related businesses)		
Synthetic Fuel	99,286	
Emulsion Products Terminal	0	
Electrotechnologies	0	
Energy Service	273	
Manufacturing	(436)	
Total current aggregate investment	$99,122	Line 4
Difference between the greater of $50 million or 15% of capitalization and the total aggregate investment of the registered holding company system (line 3 less line 4)	$2,346,850	Line 5

ITEM 5 - OTHER INVESTMENTS*

Investment Balance 11/30/00

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 11 of 49

Colona Synfuel, LLC	9,092,279
Sandy River Synfuel, LLC	29,981,746
Solid Fuel, LLC	39,022,407
Solid Energy LLC	0
Ceredo Synfuel LLC	0
Ceredo Liquid Terminal LLC	-
Progress Materials, Inc.	2,553,487
Strategic Resource Solutions	119,526,168
Utech Venture Capital Corporation	4,542,352
Utech Climate Challenge Fund, LP	2,249,375

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* These numbers do not include Electric Fuels Corporation because the Commission has determined that a majority of the assets of Electric Fuels' subsidiaries are not retainable under the standards of Section 11(b)(1) of the Act.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 12 of 49

ITEM 6 - FINANCIAL STATEMENTS

Not applicable.

SIGNATURE

Pursuant to the requirements of the Public Utility Holding Company Act of 1935, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

PROGRESS ENERGY, INC.

Registrant

Date: December 14, 2001

By: /s/ *Thomas R. Sullivan*

Name: Thomas R. Sullivan
Title: Treasurer

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 14 of 49

Dates Referenced Herein *and* Documents Incorporated By Reference

This U-9C-3 Filing	Date	Referenced-On Page First	Referenced-On Page Last	Other Filings
For The Period Ended	9/30/01	1		10-Q
Filed On / Filed As Of	12/14/01	7		35-CERT

Top

List All Filings

Alternative Formats: Rich Text / Word (.rtf), Text (.txt), EDGAR (.sgml), XML (.xml), et al.

Progress Energy

Quarterly Report to Holders of Contingent Value Obligations For the Quarter Ended December 31, 2003

To Holders of Contingent Value Obligations:

This is the quarterly report for the synthetic fuel plants owned by Solid Energy LLC, Ceredo Synfuel LLC, Solid Fuel LLC, and Sandy River Synfuel LLC ("the Earthco plants") for the quarter ending December 31, 2003.

Overview
There are currently 98.6 million Contingent Value Obligations (CVOs) issued and outstanding. CVOs were issued as a result of the Progress Energy, Inc. (Progress Energy) and Florida Progress Corporation share exchange, which occurred on November 30, 2000. For every Florida Progress Corporation share owned at that time, one CVO was issued.

Each CVO represents the right to receive contingent payments, based on the net after-tax cash flow generated by the Earthco plants. Qualifying synthetic fuel plants entitle their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuel produced and sold by these plants. In the aggregate, holders of CVOs are entitled to payments equal to 50% of any net after-tax cash flow generated by the Earthco plants in excess of $80 million per year for each of the years 2001 through 2007. Payments on the CVOs will not be made until tax audit matters are resolved. Based on past tax audit experience, it is anticipated that payments will not begin any sooner than six years after the first operation year for which the net after-tax cash flow generated by the Earthco plants exceeds $80 million.

For purposes of calculating CVO payments, net after-tax cash flows include the taxable income or loss for the Earthco plants adjusted for depreciation and other non-cash items plus income tax benefits, and minus income tax incurred. The total amount of net after-tax cash flow for any year will depend upon the final determination of the income tax savings realized and the income taxes incurred after completion of the income tax audits. Thus, the estimated after-tax cash flow generated by the Earthco plants could increase or decrease due to changes in the income tax savings realized for the year.

This is only an overview of the terms of the CVOs. The legal documents governing the CVOs contain significant additional information.

Results of Operations
The estimated net after-tax cash flow for the quarter for each of the Earthco plants is as follows:

	4th Quarter	Year to Date*
Solid Energy LLC	$ 4.8 million	$ 16.4 million
Ceredo Synfuel LLC	$ 31.9 million	$ 31.5 million
Solid Fuel LLC	$ 5.4 million	$ (3.1) million
Sandy River Synfuel LLC	$ 15.3 million	$ 2.6 million

An estimated $130.8 million in synthetic fuel tax credits were generated, but not realized nor included in the net after-tax cash flow amounts for the twelve months ended December 31, 2003.

*The Company is negotiating an escrow agreement for the payment of royalties. During 2003, the Company accrued its royalty obligations; however, no cash payments were made. The estimated net after-tax cash flow for the year would have been reduced if the payments were made. As of December 31, 2003, approximately $50.0 million of accrued royalties were on the books of the Earthco plants.

Material Developments
During 2001, the Internal Revenue Service (IRS) released Revenue Procedure 2001-30 and Revenue Procedure 2001-34 that outline the conditions that must be met to receive a Private Letter Ruling (PLR) for Section 29 tax credits from the IRS. PLRs represent advance rulings from the IRS applying its interpretation of the tax law to an entity's facts for Section 29 credits. In December 2001 and January 2002, favorable PLRs were received for all four Earthco plants.

In September 2002, all four of the Earthco plants were accepted into the IRS' Pre-Filing Agreement (PFA) program. The PFA program allows taxpayers to accelerate voluntarily the IRS exam process in order to seek resolution of specific issues. Both the Company and the IRS can withdraw from the program at any time, and issues not resolved through the program may proceed to the next level of the IRS exam process.

In late June 2003, Progress Energy was informed that IRS field auditors had raised questions regarding the chemical change associated with coal-based synthetic fuel manufactured at its Colona facility and the testing process by which the chemical change is verified. (The questions arose in connection with Progress Energy's participation in the IRS' PFA program.) In October 2003, the National Office of the IRS informed the Company that it had rejected the IRS field auditors' challenges regarding whether the synthetic fuel produced at the Company's Colona facility was the result of a significant chemical change. The National Office had concluded that the experts, engaged by Colona who test the synthetic fuel for chemical change, use reasonable scientific methods to reach their conclusions. Accordingly, the National Office will not take any adverse action on the PLR that was issued for the Colona facility.

The ruling provided by the IRS National Office addresses only Progress Energy's Colona facility. Progress Energy, however, applies essentially the same chemical process and uses the same independent laboratories to confirm chemical change in the synthetic fuel manufactured at each of its four Earthco plants. The independent laboratories used by Progress Energy to determine significant chemical change are the leading experts in their field and are used by many other industry participants. Progress Energy believes that the laboratories' work and the chemical change process are consistent with the bases upon which the PLRs were issued. However, the IRS has not yet formally informed the Company as to its position on the Company's other facilities.

In February 2004, subsidiaries of the Company finalized execution of the Colona Closing Agreement with the Internal Revenue Service concerning their Colona synthetic fuel facilities. Although the execution of the Colona Closing Agreement is a significant event, the audits of the Company's facilities are not yet completed, and the PFA process continues with respect to the four Earthco synthetic fuel facilities. Currently the focus of that process is to determine that the facilities were placed in service before July 1, 1998. Progress Energy continues to believe that is operates its facilities in conformity with its PLRs and Section 29. Progress Energy is working to resolve this matter as quickly as possible. At this time, Progress Energy cannot predict how long the IRS process will take; however, Progress Energy intends to continue working cooperatively with the IRS. Progress Energy firmly believes that it is operating the Colona facility and the Earthco plants in compliance with its PLRs and Section 29 of the Internal Revenue Code. Accordingly, Progress Energy has no current plans to alter its synthetic fuel production schedules as a result of these matters.

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29. The investigation is examining the utilization of the credits, the nature of the technologies and fuels created, the use of the synthetic fuel and other aspects of Section 29 and is not specific to the Company's synthetic fuel operations. Progress Energy is providing information in connection with this investigation. The Company cannot predict the outcome of this matter.

Adjustments for Previous Periods
Net after-tax cash flows are estimated each quarter as actual information is not available until the tax return is filed in the subsequent year. The adjusted net after-tax cash flow information for the prior year is disclosed annually in the report for the fourth quarter.

The original net after-tax cash flow estimates for the year ended December 31, 2002 for each of the Earthco plants have been adjusted to reflect amounts as filed on the 2002 federal tax returns.

The 2002 estimated net after-tax cash flow amounts for the calendar year for each of the Earthco plants are as follows:

	Year to Date
Solid Energy LLC	$ (9.4) million
Ceredo Synfuel LLC	$ 12.1 million
Solid Fuel LLC	$ (2.6) million
Sandy River Synfuel LLC	$ 2.9 million

Synthetic fuel tax credits of $94.8 million were generated, but not realized nor included in the net after-tax cash flow amounts for the year ended December 31, 2002.

Supplemental Information

Where can I find a current market value of the CVO?
CVOs are traded on the Over The Counter "pink sheets." You will need to contact your broker to obtain a value or you may go on the Internet and visit the following Web site: pinksheets.com. Click on the "symbol lookup" and type "Progress Energy" in the "Search for a security" site, click "go" then click on "quote" to obtain the latest quote.

How can I purchase or sell CVOs?
You will need to contact a broker to purchase or sell CVOs.

What is the cost basis in the CVOs?
For federal income tax reporting purposes, the Company will treat 54.5 cents as the fair market value of each CVO that was issued on November 30, 2000, the effective date of the share exchange. That amount is the average of the reported high and low trading prices of the CVOs on the NASDAQ Over The Counter Market on November 30, 2000. If you received your CVOs in the share exchange your tax basis for your CVOs is 54.5 cents. If you acquired your CVOs after the share exchange, please consult your tax advisor for your tax basis.

Who is the Securities Registrar and Transfer Agent for the CVOs?
Mellon Investor Services is the Securities Registrar and Transfer Agent.
Mellon Investor Services
P.O. Box 3338
South Hackensack, NJ 07606-1938
Call toll free 1 877-711-4092

In September 2002, all four of the Earthco plants were accepted into the IRS' Pre-Filing Agreement (PFA) program. The PFA program allows taxpayers to accelerate voluntarily the IRS exam process in order to seek resolution of specific issues. Both the Company and the IRS can withdraw from the program at any time, and issues not resolved through the program may proceed to the next level of the IRS exam process. While the ultimate outcome is uncertain, the Company believes that participation in the PFA program will likely shorten the tax examination process.

In management's opinion, Progress Energy is complying with the private letter rulings and all the necessary requirements to be allowed such credits under Section 29 and believes it is likely, although it cannot provide certainty, that it will prevail if challenged by the IRS on any credits taken.

Adjustments for Previous Periods
The original net after-tax cash flow estimates for the year ended December 31, 2001 for each of the Earthco plants have been adjusted to reflect amounts as filed on the 2001 federal tax returns.

The 2001 estimated net after-tax cash flow amounts for the calendar year for each of the Earthco plants are as follows:

	Year to Date
Solid Energy LLC	$(.2) million
Ceredo Synfuel LLC	$(8.0) million
Solid Fuel LLC	$13.6 million
Sandy River Synfuel LLC	$(4.5) million

Synthetic fuel tax credits of $114.7 million were generated, but not realized nor included in the net after-tax cash flow amounts for the year ended December 31, 2001.

Supplemental Information

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South Hackensack, NJ 07606-1938
Call toll-free 1-877-711-4092

Progress Energy

Quarterly Report to Holders of Contingent Value Obligations For the Quarter Ended December 31, 2002

To Holders of Contingent Value Obligations:

This is the quarterly report for the synthetic fuel plants owned by Solid Energy LLC, Ceredo Synfuel LLC, Solid Fuel LLC, and Sandy River Synfuel LLC ("the Earthco plants") for the quarter ended December 31, 2002.

Overview

There are currently 98.6 million Contingent Value Obligations (CVOs) issued and outstanding. CVOs were issued as a result of the Progress Energy, Inc. (Progress Energy) and Florida Progress Corporation share exchange, which occurred on November 30, 2000. For every Florida Progress Corporation share owned at that time, one CVO was issued.

Each CVO represents the right to receive contingent payments, based on the net after-tax cash flow generated by the Earthco plants. Qualifying synthetic fuel plants entitle their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuel produced and sold by these plants. In the aggregate, holders of CVOs are entitled to payments equal to 50 percent of any net after-tax cash flow generated by the Earthco plants in excess of $80 million per year for each of the years 2001 through 2007. Payments on the CVOs will not be made until tax audit matters are resolved. Based on past tax audit experience, it is anticipated that payments will not begin any sooner than six years after the first operation year for which the net after-tax cash flow generated by the Earthco plants exceeds $80 million. Based on the estimated net after-tax cash flow amounts for 2002, no payments have been made to the trust for this operation year.

For purposes of calculating CVO payments, net after-tax cash flows include the taxable income or loss for the Earthco plants adjusted for depreciation and other non-cash items plus income tax benefits, and minus income tax incurred. The total amount of net after-tax cash flow for any year will depend upon the final determination of the income tax savings realized and the income taxes incurred after completion of the income tax audits. Thus, the estimated after-tax cash flow generated by the Earthco plants could increase or decrease due to changes in the income tax savings realized for the year.

This is only an overview of the terms of the CVOs. The legal documents governing the CVOs contain significant additional information.

Results of Operations

The estimated net after-tax cash flow for the quarter and year to date for each of the Earthco plants are as follows:

	4th Quarter	Year to Date
Solid Energy LLC	$10.5 million	$(11.2) million
Ceredo Synfuel LLC	$24.8 million	$9.7 million
Solid Fuel LLC	$14.4 million	$(4.7) million
Sandy River Synfuel LLC	$13.7 million	$(0.3) million

An estimated $102.5 million in synthetic fuel tax credits were generated, but not realized nor included in the net after-tax cash flow amounts for the year ended December 31, 2002.

Material Developments

During 2001, the Internal Revenue Service (IRS) released Revenue Procedure 2001-30 and Revenue Procedure 2001-34 that outline the conditions that must be met to receive a Private Letter Ruling (PLR) for Section 29 tax credits from the IRS. PLRs represent advance rulings from the IRS applying its interpretation of the tax law to an entity's facts for Section 29 credits. In December 2001 and January 2002, favorable PLRs were received for all four Earthco plants.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 20 of 49

USG Synfuel Projects

Secondary Coal Recovery System

U.S. Global, LLC ("USG") acted as co-developer and monetization agent with respect to 4 SCRS Facilities (the "Facilities") originally constructed by an Indianapolis based company called Earthco, which specializes in the recovery of under valued natural resources including coal fines. The Facilities convert coal fines, the readily available, low-grade coal powder produced as a natural by-product of coal mining or processing, into transportable, higher BTU briquettes ("synthetic fuel" or "synfuel").

Each Facility is design rated at a capacity of 1.3 million tons of synfuel per year and qualifies under Section 29 of the tax code to earn tax credits from the production and sale of non-conventional energy resources. On one of the Facilities, a Private Letter Ruling ("PLR") was originally issued by the IRS confirming the qualification of the coal produced by those Facilities for Section 29 tax credits through December 31, 2007, the termination date of the Section 29 program.

Earthco anticipated substantial revenues from the sale of ownership interests in the Facilities and initially engaged U.S. Global to raise funds against these future revenues. However, Earthco had located the facilities at sites that prevented them from gaining access to large coal markets, had no long-term off-take contracts for the synfuel (creating uncertainty as to exactly how many tax credits could be generated) and had numerous other difficulties which made the transaction too risky for potential investors.

In order to realize the potential value of the assetts, U.S. Global approached the utility industry to find potential partners with the ability to:

1) Relocate the Facilities to appropriate sites

2) Operate the facilities at reliable levels of production

3) Either purchase the synfuel directly or re-market it to 3rd Parties

4) Benefit from all or a portion of the tax credits generated by the facilities.

U.S. Global developed a financial structure which would accommodate both active and passive partners and approached major companies both inside and outside of the utility industry to act as passive partners.

U.S. Global succeeded in its objective of developing the structure necessary to realize the asset value of the Facilities. Florida Progress, a major Florida electric utility company, purchased the four Facilities through its Electric Fuels Corporation subsidiary.

EFC, the largest producer of synfuel in the United States, relocated the Facilities to its own coal mine and river terminal sites on the East coast in January of 2000. EFC is responsible for feedstock supply, operations and maintenance and synfuel sale for each Facility. In 2002, Private Letter Rulings were issued on all four facilities. Full production and sales of 8.8-10.0 million tons per annum are expected with annual tax credit production of approximately $228-260 million through the expiration of the Tax Credit in January, 2008.

Carolina Power & Light merged with Florida Progress to form Progress Energy (NYSE:PGN). Beginning in 2002, the Facilities acheived satisfactory operating levels. They are expected to continue contributing approximately $140 million to Progress Energy, in after-tax earnings per annum.
Progress Energy Press Release regarding the 4 Synfuel Facilities

U.S. Global, LLC • 953 Hillsboro Mile, Hillsboro Beach, Florida, 33062, US

Progress Energy Inc U-9C-3 For 9/30/01

Filed On 12/14/01 SEC File 74-00051 Accession Number 950168-1-501405

As Of	Filer	Filing	As/For/On	Docs:Pgs	Issuer	Agent
12/14/01	Progress Energy Inc	U-9C-3	9/30/01	1:7		Donne

Quarterly Report of an Energy or Gas-Related Company Form U-9C-3
Filing Table of Contents

Document/Exhibit	Description	Pages	Size
1: U-9C-3	Quarterly Report of an Energy or Gas-Related Company	7	33K

Document Table of Contents

- Item 5 -. Other Investments*
- Item 6 -. Financial Statements

- Other Investments*
- Summary of Aggregate Investment

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 23 of 49

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM U-9C-3

QUARTERLY REPORT

FOR THE QUARTER ENDED September 30, 2001

Filed Pursuant to Rule 58 of the Public Utility Holding Company Act of 1935

PROGRESS ENERGY, INC.
410 S. Wilmington Street
Raleigh, NC 27602

[Download Table]

Contents ***Page***

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 24 of 49

[Enlarge/Download Table]

ITEM 1 - ORGANIZATION CHART

Name of Reporting Company	*Energy or Gas Related*	*State of Organization*	*Percentage of Voting Securities Held*	*Natur*
Progress Ventures, Inc.	Energy	NC		
CPL Synfuels LLC	Energy	NC	100	Synthetic
Solid Fuel LLC	Energy	DE	90	Synthetic
Sandy River Synfuel LLC	Energy	DE	90	Synthetic
Colona Synfuel LLLP	Energy	DE	17	Synthetic
Strategic Resource Solutions Corp.	Energy	NC	100	Energy Ser
SRS Engineering Corp.	Energy	NC	100	Energy Eng
Spectrum Controls, Inc.	Energy	NC	100	Energy Con
Electric Fuels Corporation	Energy	FL	100	Procuremen Transporta
EFC Synfuel LLC	Energy	DE	100	Holding Co
Ceredo Synfuel LLC	Energy	DE	99	Synthetic
Sandy River Synfuel LLC	Energy	DE	9	Synthetic
Solid Energy LLC	Energy	DE	99	Synthetic
Solid Fuel LLC	Energy	DE	9	Synthetic
Kentucky May Coal Company, Inc.	Energy	VA	100	Coal Mine
Cincinnati Bulk Terminals, Inc.	Energy	DE	100	Coal and B Terminal
Kanawha River Terminals, Inc.	Energy	FL	100	Coal and B Terminal
Black Hawk Synfuel, LLC	Energy	DE	100	Synthetic
New River Synfuel LLC	Energy	CO	10	Synthetic
Ceredo Liquid Terminal LLC	Energy	DE	100	Emulsion P
Coal Recovery V, LLC	Energy	MO	25	Synthetic
Colona Newco, LLC	Energy	DE	100	Holding Co
Colona SynFuel Limited Partnership, LLLP	Energy	DE	20.1	Synthetic
Colona Sub No. 2, LLC	Energy	DE	100	Synthetic
Colona Synfuel Limited Partnership, LLLP	Energy	DE	1	Synthetic
Colona Synfuel Limited Partnership, LLLP	Energy	DE	61.9	Synthetic
Progress Materials, Inc.	Energy	FL	100	Manufactur

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 25 of 49

Progress Synfuel Holdings, Inc.	Energy	DE	100	Holding Co
Ceredo Synfuel LLC	Energy	DE	1	Synthetic
Sandy River Synfuel LLC	Energy	DE	1	Synthetic
Solid Energy LLC	Energy	DE	1	Synthetic
Solid Fuel LLC	Energy	DE	1	Synthetic
Utech Venture Capital Corporation	Energy	DE	9.76	Investment Electrotec
Utech Climate Challenge Fund	Energy	DE	9.8	Investment Electrotec

2

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 26 of 49

[Enlarge/Download Table]

ITEM 2 - ISSUANCES AND RENEWALS OF SECURITIES AND CAPITAL CONTRIBUTION

Contribution Date	Company Making Contribution	Company Receiving Contribution	Contribution Amount
07/24/2001	EFC Synfuel, LLC	Solid Fuel, LLC	602,376.55
07/24/2001	Progress Synfuel Holdings, Inc.	Solid Fuel, LLC	66,930.73
07/30/2001	CPL Synfuels, LLC	Solid Fuel, LLC	6,023,765.49
08/28/2001	EFC Synfuel, LLC	Solid Fuel, LLC	428,741.54
08/28/2001	Progress Synfuel Holdings, Inc.	Solid Fuel, LLC	47,637.95
08/30/2001	CPL Synfuels, LLC	Solid Fuel, LLC	4,287,415.42
07/24/2001	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	84,502.86
07/24/2001	EFC Synfuel, LLC	Sandy River Synfuel, LLC	760,525.69
08/31/2001	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	58,193.51
08/31/2001	EFC Synfuel, LLC	Sandy River Synfuel, LLC	523,741.63
09/26/2001	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	12,043.25
09/26/2001	EFC Synfuel, LLC	Sandy River Synfuel, LLC	108,389.28
07/30/2001	CPL Synfuels, LLC	Sandy River Synfuel, LLC	7,605,256.92
08/30/2001	CPL Synfuels, LLC	Sandy River Synfuel, LLC	5,237,416.29
09/28/2001	CPL Synfuels, LLC	Sandy River Synfuel, LLC	1,083,892.73

Dividend Date	Company Making Dividend	Company Receiving Dividend	Dividend Amount

None to report for this quarter.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 27 of 49

U-9C-3 | 4th Page of 7 | TOC | 1st | Previous | Next | Bottom | Just 4th

[Enlarge/Download Table]

ITEM 3. ASSOCIATE TRANSACTIONS

Part I - Transactions Performed by Reporting Companies on Behalf of Associate Companies

Reporting Company Rendering Services	Associate Company Receiving Services	Types of Services Rendered	Direct Costs Charged	Indirect Costs Charged	Cost Capit
SRS	CP&L	Energy Management	1,401,085		
Sandy River, LLC	Cincinnati Bulk Terminal, Inc.	Coal sales	568,099		
	Kentucky Coal Terminal, Inc.	Coal sales	8		
	Colona Synfuel, LLC	Coal sales	(437,591)		
Electric Fuels Corporation	Florida Power	Coal Sales	61,594,799		
Electric Fuels Corporation	Kanawha River Terminals, Inc	Coal Sales	5,110,756		
Electric Fuels Corporation	Florida Progress	Admin Services	2,264		
Electric Fuels Corporation	Florida Power	Admin Services	7,833		
Electric Fuels Corporation	Progress Energy Corporation	Admin Services	1,408		
Electric Fuels Corporation	CP & L	Admin Services	137,840		
Electric Fuels Corporation	Progress Land	Admin Services	35,987		
Electric Fuels Corporation	Little Black Mountain Coal Reserves Inc.	Admin Services	7,343		
Electric Fuels Corporation	Homeland Coal Company, Inc.	Admin Services	30,451		
Electric Fuels Corporation	Awayland Coal Company, Inc.	Admin Services	29,690		
Electric Fuels Corporation	Powell Mountain Joint Venture	Admin Services	277,926		
Electric Fuels Corporation	Powell Mountain Coal Company	Admin Services	316,470		

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 28 of 49

Electric Fuels Corporation	Murphy Land Company	Admin Services	3,559
Electric Fuels Corporation	Mesa Hydrocarbons, Inc.	Admin Services	6,487
Electric Fuels Corporation	Progress Synfuel Holdings, Inc	Admin Services	3,569
Electric Fuels Corporation	EFC Synfuel, LLC	Admin Services	185,963
Electric Fuels Corporation	Ceredo Synfuel, LLC	Admin Service	69,430
Electric Fuels Corporation	Marine River Terminals	Admin Services	5,915

4

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 29 of 49

[Enlarge/Download Table]

Electric Fuels Corporation	Progress Rail Services Corporation	Admin Services	1,325,772	1,325,772
Electric Fuels Corporation	Progress Materials, Inc.	Admin Services	413,550	413,550
Electric Fuels Corporation	Kentucky May Coal Company, Inc.	Admin Services	467,706	467,706
Electric Fuels Corporation	Diamond May Coal Company	Admin Services	279,533	279,533
Electric Fuels Corporation	Kentucky May Mining Company	Admin Services	227,736	227,736
Electric Fuels Corporation	Cincinnati Bulk Terminals, Inc.	Admin Services	167,097	167,097
Electric Fuels Corporation	Kanawha River Terminals, Inc.	Admin Services	956,718	956,718
Electric Fuels Corporation	Colona	Admin Services	114,633	114,633
Electric Fuels Corporation	Black Hawk	Admin Services	154,701	154,701
Electric Fuels Corporation	Ceredo Liquid Terminals, LLC	Admin Services	67,751	67,751
Colona Synfuel, LLC	Kentucky Coal Terminal, Inc.	Coal Sales	100,967	100,967

[Enlarge/Download Table]

ITEM 3.

Part II - Transactions Performed by Associate Companies on Behalf of Reporting Companies

Associate Company Rendering Services	*Reporting Company Receiving Services*	*Types of Services Rendered*	*Direct Costs Charged*	*Indirect Costs Charged*	*Cost o Capita*
Progress Energy Services	SRS	Admin Services	376,520	411,857	
CP&L	SRS	Admin Services	166,531		

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 30 of 49

Powell Mountain Joint venture	Solid Fuel, LLC	Admin Services	19,029,026
Florida Power	Electric Fuels Corporation	Admin Services	473,248
Progress Energy, Inc.	Electric Fuels Corporation	Admin Services	47,992
Progress Energy Service Corporation	Electric Fuels Corporation	Admin Services	739,056
Progress Ventures	Electric Fuels Corporation	Admin Services	567,499
Powell Mountain Joint Venture	Electric Fuels Corporation	Coal Sales	3,617,320
Memco Barge Lines, Inc.	Electric Fuels Corporation	Barge Transportation	5,864,049
Kanawha River Terminals, Inc.	Electric Fuels Corporation	Coal Sales	1,365,712
Black Hawk Synfuel, LLC	Electric Fuels Corporation	Coal Sales	11,797,883
Electric Fuels Corporation	Sandy River Synfuels, LLC	Coal Sales	8
Black Hawk Synfuel, LLC	Sandy River Synfuels, LLC	Coal Sales	5,033

5

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No.__ (RS-16)
Page 31 of 49

[Enlarge/Download Table]

Kentucky May Coal Company, Inc.	Sandy River Synfuels, LLC	Admin Services	7,500,935	7,500,935
Kentucky Coal Terminal, Inc	Colona Synfuel, LLC	Coal Sales	25,525,922	25,525,922
Kentucky Coal Terminal, Inc	Colona Synfuel, LLC	Land Rent	6,000	6,000
Black Hawk Synfuel, LLC	Colona Synfuel, LLC	Coal Sales	780,645	780,645
Ceredo Liquid Terminal	Colona Synfuel, LLC	Admin Services	2,519,158	2,519,158

[Enlarge/Download Table]

ITEM 4 - SUMMARY OF AGGREGATE INVESTMENT

Investments in energy-related companies:	(000's)	
Total consolidated capitalization as of 9/30/01.	$16,306,485	Line 1
Total capitalization multiplied by 15% (line 1 multiplied by 0.15)	$2,445,973	Line 2
Greater of $50 million or line 2	$2,445,973	Line 3
Total current aggregate investment: (categorized by major line of energy related businesses)		
Synthetic Fuel	99,286	
Emulsion Products Terminal	0	
Electrotechnologies	0	
Energy Service	273	
Manufacturing	(436)	
Total current aggregate investment	$99,122	Line 4
Difference between the greater of $50 million or 15% of capitalization and the total aggregate investment of the registered holding company system (line 3 less line 4)	$2,346,850	Line 5

ITEM 5 - OTHER INVESTMENTS*

Investment Balance	11/30/00

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 32 of 49

Colona Synfuel, LLC	9,092,279
Sandy River Synfuel, LLC	29,981,746
Solid Fuel, LLC	39,022,407
Solid Energy LLC	0
Ceredo Synfuel LLC	0
Ceredo Liquid Terminal LLC	-
Progress Materials, Inc.	2,553,487
Strategic Resource Solutions	119,526,168
Utech Venture Capital Corporation	4,542,352
Utech Climate Challenge Fund, LP	2,249,375

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* These numbers do not include Electric Fuels Corporation because the Commission has determined that a majority of the assets of Electric Fuels' subsidiaries are not retainable under the standards of Section 11(b)(1) of the Act.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 33 of 49

ITEM 6 - FINANCIAL STATEMENTS

Not applicable.

SIGNATURE

Pursuant to the requirements of the Public Utility Holding Company Act of 1935, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

PROGRESS ENERGY, INC.

Registrant

Date: December 14, 2001

By: /s/ ***Thomas R. Sullivan***

Name: Thomas R. Sullivan
Title: Treasurer

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 34 of 49

Dates Referenced Herein ***and*** **Documents Incorporated By Reference**

This U-9C-3 Filing	***Date***	***Referenced-On Page First***	***Last***	***Other Filings***
For The Period Ended	9/30/01	1		10-Q
Filed On / Filed As Of	12/14/01	7		35-CERT

Top List All Filings

Alternative Formats: Rich Text / Word (.rtf), Text (.txt), EDGAR (.sgml), XML (.xml), et al.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 35 of 49

Progress Energy Inc U-9C-3 For 3/31/03

Filed On 5/30/03 2:56pm ET SEC File 74-00051 Accession Number 1094093-3-39

As Of	Filer	Filing	As/For/On	Docs:Pgs
5/30/03	Progress Energy Inc	U-9C-3	3/31/03	1:7

Quarterly Report of an Energy or Gas-Related Company Form U-9C-3

Filing Table of Contents

Document/Exhibit	Description	Pages	Size
1: U-9C-3	1st Qtr 2003 U-9C-3 Progress Energy	7	35K

Document Table of Contents

Page *(sequential)* *(alphabetic)* Top

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 36 of 49

" Item 6 -. Financial Statements

- Summary of Aggregate Investment

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 37 of 49

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM U-9C-3

QUARTERLY REPORT

FOR THE QUARTER ENDED March 31, 2003

Filed Pursuant to Rule 58 of the Public Utility Holding Company Act of 1935

PROGRESS ENERGY, INC.
410 S. Wilmington Street
Raleigh, NC 27602

Contents Page

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 38 of 49

ITEM 1 - ORGANIZATION CHART

[Enlarge/Download Table]

Name of Reporting Company	Energy or Gas Related	State of Organization	Percentage of Voting Securities Held	Nature of Business
Progress Ventures, Inc.	Energy	NC	100	Holding Company
CPL Synfuels LLC(1)	Energy	NC	100	Synthetic Fuel Produc
Solid Fuel LLC	Energy	DE	90	Synthetic Fuel Produc
Sandy River Synfuel LLC	Energy	DE	90	Synthetic Fuel Produc
Colona Synfuel LLLP	Energy	DE	17	Synthetic Fuel Produc
Strategic Resource Solutions Corp.	Energy	NC	100	Energy Services Compa
Progress Energy Solutions, Inc.	Energy	NC	100	Energy Services Compa
PES Engineering Corp.	Energy	NC	100	Energy Engineering
Progress Fuels Corporation	Energy	FL	100	Procurement and Transportation of Coa
EFC Synfuel LLC	Energy	DE	100	Holding Company
Ceredo Synfuel LLC	Energy	DE	99	Synthetic Fuel Produc
Sandy River Synfuel LLC	Energy	DE	9	Synthetic Fuel Produc
Solid Energy LLC	Energy	DE	99	Synthetic Fuel Produc
Solid Fuel LLC	Energy	DE	9	Synthetic Fuel Produc
Kentucky May Coal Company, Inc.	Energy	VA	100	Coal Mine
KRT Holdings, Inc.(2)	Energy	DE	100	Coal and Bulk Materia Terminal
Kanawha River Terminals, Inc.	Energy	FL	100	Coal and Bulk Materia Terminal
Black Hawk Synfuel, LLC	Energy	DE	100	Synthetic Fuel Produc
New River Synfuel LLC	Energy	CO	10	Synthetic Fuel Produc
Ceredo Liquid Terminal LLC	Energy	DE	100	Emulsion Products Ter
Coal Recovery V, LLC	Energy	MO	25	Synthetic Fuel Market
Colona Newco, LLC	Energy	DE	100	Holding Company
Colona SynFuel Limited Partnership, LLLP	Energy	DE	20.1	Synthetic Fuel Produc
Colona Sub No. 2, LLC	Energy	DE	100	Synthetic Fuel Produc
Colona Synfuel Limited Partnership, LLLP	Energy	DE	1	Synthetic Fuel Produc
Colona Synfuel Limited Partnership, LLLP	Energy	DE	61.9	Synthetic Fuel Produc
Marmet Synfuel, LLC	Energy	DE	100	Synthetic Fuel Produc

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 39 of 49

Progress Materials, Inc.	Energy	FL	100	Manufacturing
Progress Synfuel Holdings, Inc.	Energy	DE	100	Holding Company
Ceredo Synfuel LLC	Energy	DE	1	Synthetic Fuel Produc
Sandy River Synfuel LLC	Energy	DE	1	Synthetic Fuel Produc
Solid Energy LLC	Energy	DE	1	Synthetic Fuel Produc
Solid Fuel LLC	Energy	DE	1	Synthetic Fuel Produc
Riverside Synfuel, LLC.	Energy	WV	100	Synthetic Fuel Produc
Utech Venture Capital Corporation	Energy	DE	11.56(3)	Investment in Electrotechnologies
Utech Climate Challenge Fund	Energy	DE	9.76	Investment in Electrotechnologies

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(1) CPL Synfuels, LLC will be renamed PV Synfuels, LLC in the second quarter of 2003.

(2) KRT Holdings, Inc. was formerly known as Cincinnati Bulk Terminals, Inc.

(3) Based on the 2002 K-1 information, it was determined that the ownership percentage is 11.56% not 9.76% as previously reported.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 40 of 49

U-9C-3	3rd Page of 7	TOC	1st	Previous	Next	Bottom	Just 3rd

ITEM 2 - ISSUANCES AND RENEWALS OF SECURITIES AND CAPITAL CONTRIBUTION

[Enlarge/Download Table]

Contribution Date	Company Making Contribution	Company Receiving Contribution	Contribution Amount (in $)
01/31/2003	CP&L Synfuels, LLC	Solid Fuel, LLC	782,212.69
01/31/2003	EFC Synfuel, LLC	Solid Fuel, LLC	78,221.27
01/31/2003	Progress Synfuel Holdings, Inc.	Solid Fuel, LLC	8,691.25
01/31/2003	CP&L Synfuels, LLC	Sandy River Synfuel, LLC	1,301,075.78
01/31/2003	EFC Synfuel, LLC	Sandy River Synfuel, LLC	130,107.58
01/31/2003	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	14,456.40
01/31/2003	Progress Energy, Inc.	Progress Energy Solutions, Inc.	8,000,000.00
02/28/2003	CP&L Synfuels, LLC	Solid Fuel, LLC	4,364,004.03
02/28/2003	EFC Synfuel, LLC	Solid Fuel, LLC	436,400.40
02/28/2003	Progress Synfuel Holdings, Inc.	Solid Fuel, LLC	48,488.93
02/28/2003	CP&L Synfuels, LLC	Sandy River Synfuel, LLC	1,668,657.36
02/28/2003	EFC Synfuel, LLC	Sandy River Synfuel, LLC	166,865.74
02/28/2003	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	18,540.64
03/31/2003	CP&L Synfuels, LLC	Solid Fuel, LLC	4,532,589.00
03/31/2003	EFC Synfuel, LLC	Solid Fuel, LLC	453,258.90
03/31/2003	Progress Synfuel Holdings, Inc.	Solid Fuel, LLC	50,362.10
03/31/2003	CP&L Synfuels, LLC	Sandy River Synfuel, LLC	6,025,991.87
03/31/2003	EFC Synfuel, LLC	Sandy River Synfuel, LLC	602,599.19
03/31/2003	Progress Synfuel Holdings, Inc.	Sandy River Synfuel, LLC	66,955.47

Dividend Date	Company Making Dividend	Company Receiving Dividend	Dividend Amount
01/31/2003	Strategic Resource Solutions Corp.	Progress Energy, Inc.	8,000,000.00

3

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 41 of 49

ITEM 3. ASSOCIATE TRANSACTIONS

[Enlarge/Download Table]

Part I - Transactions Performed by Reporting Companies on Behalf of Associate Companies

Reporting Company Rendering Services	Associate Company Receiving Services	Types of Services	Direct Costs Charged (in $)	Indirect Costs Charged (in $)	Cost o Capital $)
Strategic Resource Solutions Corp.	Carolina Power and Light Company	Energy Management	106,400		
Progress Energy Service Co., LLC	Carolina Power and Light Company	Energy Management	1,524,598.47		
Progress Materials, Inc.	Carolina Power and Light Company	Engineering Services	56,560	21,440	
Progress Fuels Corporation	Florida Power Corporation	Coal Sales	81,931,840		
Progress Fuels Corporation	Kanawha River Terminals, Inc.	Coal Sales	659,794		
Progress Fuels Corporation	Riverside Synfuel, LLC	Coal Sales	403,801		
Progress Fuels Corporation	Florida Power Corporation	Admin Services	25,908		
Progress Fuels Corporation	Progress Energy, Inc.	Benefits-Related	719,993		
Progress Fuels Corporation	Carolina Power and Light Company	Admin Services	23,653		
Progress Fuels Corporation	Progress Land Corporation	Admin Services	49,063		
Progress Fuels Corporation	Dulcimer Land Company, Inc.	Admin Services	38,776		
Progress Fuels Corporation	Homeland Coal Company, Inc.	Admin Services	48,076		
Progress Fuels Corporation	Awayland Coal Company, Inc.	Admin Services	23,775		
Progress Fuels Corporation	Powell Mountain Joint Venture	Admin Services	157,116		
Progress Fuels Corporation	Powell Mountain Coal Company, Inc.	Admin Services	433,902		
Progress Fuels Corporation	Mesa Hydrocarbons, Inc.	Admin Services	102,291		
Progress Fuels Corporation	Westchester Gas Company, Ltd.	Admin Services	177,581		
Progress Fuels Corporation	Progress Fuels North Texas Gas, LP	Admin Services	7,077		
Progress Fuels Corporation	Progress Synfuel Holdings, Inc.	Admin Services	3,898		
Progress Fuels Corporation	EFC Synfuel, LLC	Admin Services	139,265		
Progress Fuels Corporation	Solid Energy, LLC	Admin Services	34		

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 42 of 49

Progress Fuels Corporation	Ceredo Synfuel, LLC	Admin Services	40,733
Progress Fuels Corporation	Sandy River Synfuel, LLC	Admin Services	3,886
Progress Fuels Corporation	Marmet Synfuel, LLC	Admin Services	56,881
Progress Fuels Corporation	Riverside Synfuel, LLC	Admin Services	1,517
Progress Fuels Corporation	Progress Rail Services Corporation	Admin Services	1,492,162
Progress Fuels Corporation	Progress Materials, Inc.	Admin Services	440,301
Progress Fuels Corporation	Kentucky May Coal Company, Inc.	Admin Services	876,348
Progress Fuels Corporation	Diamond May Coal Company	Admin Services	443,260
Progress Fuels Corporation	Kentucky May Mining Company	Admin Services	469,684
Progress Fuels Corporation	KRT Holdings, Inc.	Admin Services	329,845
Progress Fuels Corporation	Kanawha River Terminals, Inc.	Admin Services	1,467,732
Progress Fuels Corporation	Colona Synfuel Limited Partnership, LLLP	Admin Services	55.532
Progress Fuels Corporation	Black Hawk Synfuel LLC	Admin Services	158,409
Progress Fuels Corporation	Ceredo Liquid Terminal, LLC	Admin Services	92,731

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 43 of 49

ITEM 3.

[Enlarge/Download Table]

Part II - Transactions Performed by Associate Companies on Behalf of Reporting Companies

Associate Company Rendering Services	Reporting Company Receiving Services	Types of Services Rendered	Direct Costs Charged (in $)	Indirect Costs Charged (in $)	Cost Capital $)
Progress Energy Service Co., LLC	Strategic Resource Solutions Corp.	Admin Services	(414,747)		
North Carolina Natural Gas Corporation	Strategic Resource Solutions Corp	Admin Services	264		
Progress Energy Service Co., LLC	Progress Energy Solutions, Inc.	Admin Services	93,642		
Powell Mountain Joint Venture	Solid Fuel, LLC	Admin Services	22,660,710		
Carolina Power and Light Company	Progress Fuels Corporation	Admin Services	292,266		
Florida Power Corporation	Progress Fuels Corporation	Admin Services	124,818		
Progress Energy, Inc.	Progress Fuels Corporation	Benefits-Related	61,044		
Progress Energy Service Co, LLC	Progress Fuels Corporation	Admin Services	18,395,350		
Progress Ventures, Inc.	Progress Fuels Corporation	Admin Services	132,593		
Marmet Synfuel, LLC	Progress Fuels Corporation	Coal/Synfuel Sales	4,284,212		
Riverside Synfuel, LLC	Progress Fuels Corporation	Coal/Synfuel Sales	424,257		
Kanawha River Terminals, Inc.	Progress Fuels Corporation	Coal Sales	6,029,277		
Black Hawk Synfuel, LLC	Progress Fuels Corporation	Coal/Synfuel Sales	845,289		
Kanawha River Terminals, Inc.	Sandy River Synfuels, LLC	Coal Sales	20,998,234		
Kanawha River Terminals, Inc.	Sandy River Synfuels, LLC	Admin Services	5,852,485		
Kanawha River Terminals, Inc.	Colona Synfuel Partnership LLLP	Coal Sales	21,353,653		
Kanawha River Terminals, Inc.	Colona Synfuel Partnership LLLP	Land Rent	6,000		

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 44 of 49

Ceredo Liquid Terminal, LLC	Colona Synfuel Partnership LLLP	Admin Services	512,830
Florida Power Corporation	Progress Materials, Inc.	Facilities Costs	27,847
Florida Power Corporation	Progress Materials, Inc.	Fuel Sales	127,840

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 45 of 49

(4) These numbers do not include Progress Fuels Corporation (f/k/a Electric Fuels Corporation) because the Commission has determined that a majority of the assets of Progress Fuels Corporation's subsidiaries are not retainable under the standards of Section 11(b)(1) of the Act

6

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-16)
Page 46 of 49

ITEM 4 - SUMMARY OF AGGREGATE INVESTMENT

[Enlarge/Download Table]

Investments in energy-related companies:	(in 000's)	
Total consolidated capitalization as of 03/31/03.	$ 17,902,072	Line 1
Total capitalization multiplied by 15% (line 1 multiplied by 0.15)	$ 2,685,311	Line 2
Greater of $50 million or line 2	$ 2,685,311	Line 3
Total current aggregate investment: (categorized by major line of energy related businesses)		
Synthetic Fuel	227,640	
Emulsion Products Terminal	0	
Electrotechnologies	0	
Energy Service	8,273	
Manufacturing	(937)	
Total current aggregate investment	$ 234,975	Line 4
Difference between the greater of $50 million or 15% of capitalization and the total aggregate investment of the registered holding company system (line 3 less line 4)	$ 2,450,336	Line 5

ITEM 5 - OTHER INVESTMENTS(4)

Investment Balance	11/30/00
Colona Synfuel, LLLP	9,092,279
Sandy River Synfuel, LLC	29,981,746
Solid Fuel, LLC	39,022,407
Solid Energy LLC	-
Ceredo Synfuel LLC	-
Ceredo Liquid Terminal LLC	-
Progress Materials, Inc.	2,553,487
Strategic Resource Solutions Corp.	119,526,168
Utech Venture Capital Corporation	4,542,352
Utech Climate Challenge Fund, LP	2,249,375

ITEM 6 - FINANCIAL STATEMENTS

Not applicable.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No.__ (RS-16)
Page 47 of 49

U-9C-3 **Last Page of 7** | TOC 1st Previous Next | Bottom Just 7th

SIGNATURE

Pursuant to the requirements of the Public Utility Holding Company Act of 1935, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

PROGRESS ENERGY, INC.
Registrant

Date: May 30, 2003

By:

Name: Thomas R. Sullivan
Title: Treasurer

Dates Referenced Herein ***and*** **Documents Incorporated By Reference**

This U-9C-3 Filing	*Date*	*Referenced-On Page* *First*	*Last*	*Other Filings*
For The Period Ended	3/31/03	1		10-Q, 8-K, DEF 14A
Filed On / Filed As Of	5/30/03	7		8-K

Top List All Filings

Alternative Formats: Rich Text / Word (`.rtf`), Text (`.txt`), EDGAR (`.sgml`), XML (`.xml`), et al.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No.__ (RS-16)
Page 49 of 49

Exhibit ____ (RS-17)

Dock Map

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. _ (RS-17)
Page 1 of 1

Exhibit 10
Page 1 of 1

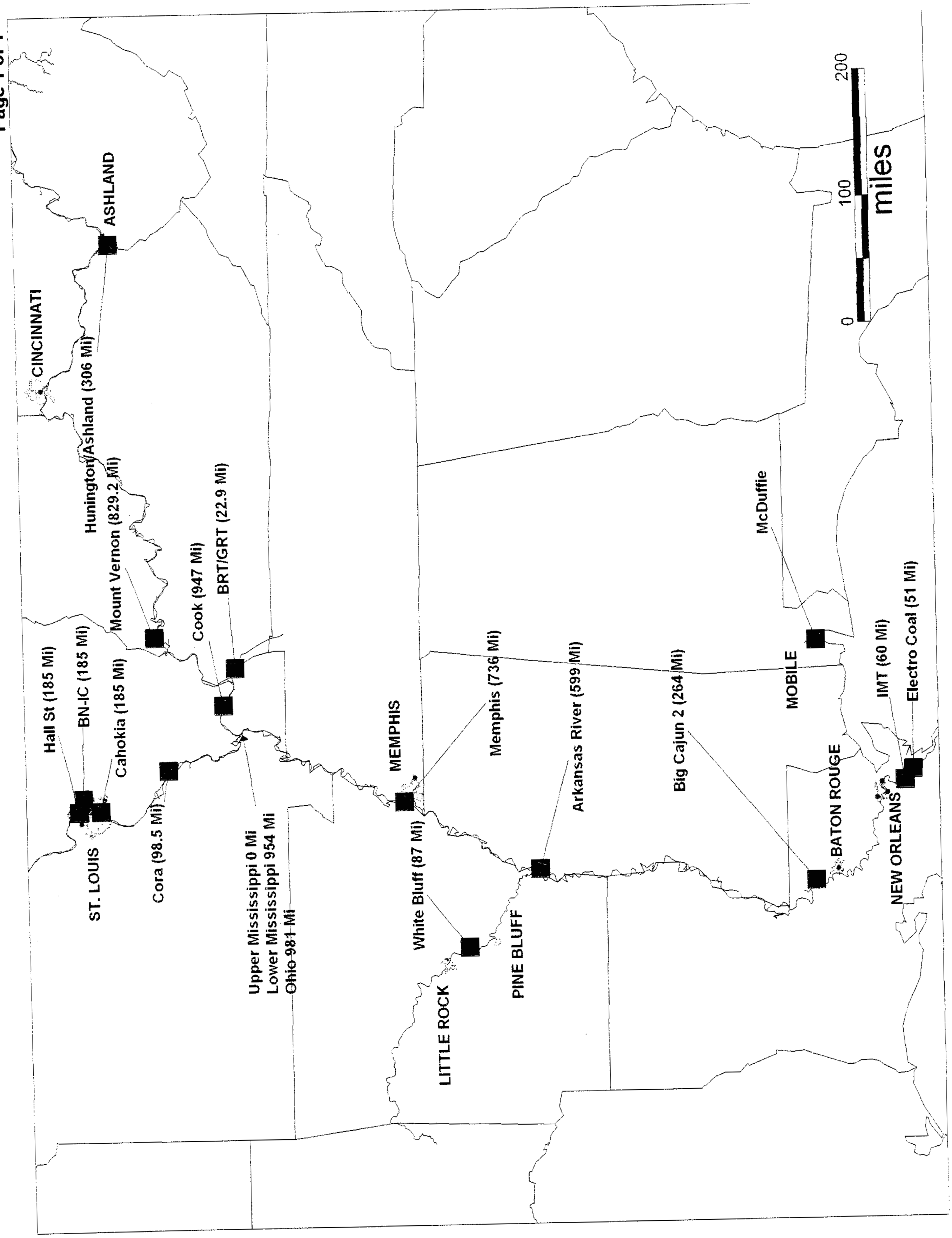


Exhibit ____ (RS-18)

September 2004 High Priced Import Purchases

Page 1 of 1

September 2004 Import Purchases

Country	Tons	$/Ton	Transport To IMT $/Ton	Transport IMT To CR 4/5 $/Ton	Total $/Ton	$/MMBtu
Venezuela	46,703	81.20	3.74	6.96	91.90	3.55
Colombia	76,632	63.39	3.74	6.96	74.09	3.15
Colombia	74,612	70.00	3.74	6.96	80.70	3.45
	197,947					

Exhibit ____ (RS-19)

$/MMBtu of Different Coals to Crystal River Units 4 and 5 via IMT Water Route and All Rail

Page 1 of 1

\$/MMBtu Of Different Coals Delivered To Crystal River 4/5 via IMT Water Route And All Rail

	Water Route			All Rail
Year	Actual[1] PFC Synfuel/CAPP	Actual[1] Imports	Available[2] PRB	CAPP[1] Coal
2000	1.95	None	1.81	1.86
2001	2.46	2.29	1.96	2.14
2002	2.29	2.69	1.90	2.23
2003	2.63	2.02	1.99	2.23
2004	2.33	2.24	1.83	2.26
2005	2.92	2.16	1.87	2.64

(1) FERC and FPSC 423 data.

(2) 2000-2002 based on PRB coal delivered to ECT by TECO as reported to FERC. 2003 is 2002 PRB price to ECT escalated by increase in Southeast delivered PRB price from 2002 to 2003. These prices were reported delivered to New Orleans; therefore, they are adjusted to a delivered to Crystal River 4/5 price by adding the Gulf barge rate charged by PEF affiliate Dixie Barge. 2004 and 2005 prices are based on bids received by PEF in July 2003 and May 2004.

Exhibit ____ (RS-20)

Delivered Crystal River Units 4 and 5 Prices via McDuffie vs. via IMT

Comparing PRB Prices via IMT vs. via Mobile

	$/Ton 2003 Vintage	
	To CR 4/5 via IMT	To CR 4/5 via Mobile
FOB Mine	6.50	6.50
Rail in Railroad Cars	11.50 To Cook & Transload	17.00 To Mobile
Barge to New Orleans	4.50	N/A
Transload to Gulf Barge	1.75	1.75
Gulf Barge	9.39	8.39
Total	**33.64**	**33.64**
$/MMBtu @ 17.6 MMBTU/ton	1.91	1.91

Exhibit ____ (RS-21)

PRB Coal Compared With Bituminous Coal/Synfuels

to New Orleans

Exhibit ___ (RS-21)
Page 1 of 1

PRB Coal Compared With Bituminous Coal/Synfuels To New Orleans

Year	PRB To New Orleans ECT ($/MMBTU)	Bituminous Coal And Synfuels For CR 4/5 To New Orleans At IMT ($/MMBTU)	Difference: Bituminous Coal More Expensive ($/MMBTU)	Equivalent $/Ton On 12,500 Btu/lb Bituminous Coal Basis ($/MMBTU)
1996	1.42	1.71	0.29	7.25
1997	1.41	1.73	0.32	8.00
1998	1.34	1.73	0.39	9.75
1999	1.26	1.67	0.41	10.75
2000	1.34	1.64	0.30	7.50
2001	1.42	2.03	0.61	15.25
2002	1.36	2.19	0.83	20.75
2003*	1.46	2.10	0.64	16.00

* Escalated from 2002.

Exhibit ____ (RS-22)

PRB Meeting at Crystal River Units 4 and 5

Progress Energy

memo

Date: October 4, 2005

To: 9/27/05 CRN PRB Meeting Attendees

CC: Charlie Gates, Bernie Cumbie, Michael Reid, Ed Brewer

From: Dan Donochod

Subject: 9/27/05 Crystal River North – PRB Blend Potential ***MEETING MINUTES – v2***

The purpose of the 9/27/05 meeting at CRN Conference Room was to present Sargent & Lundy's (S&L) report findings and for Strategic Engineering to present financial evaluation of PRB blends. A list of those attending the meeting/conference call is attached.

The basis of the meeting was to explain the findings of < 30% PRB blend use for barged coal. The PowerPoint presentation used for this meeting can be found at:

Shortcut to PRB USE update-plant-9-27-05.ppt.lnk

1. **Background**: Dan D. opened by explaining the pathway to current PRB evaluation, study assumptions, benefits and concerns with PRB use. PRB under consideration would be preblended off-site (IMT Terminal) and used < 30%. Even with projected coal trends which lessen the difference between CAPP and PRB prices, a 20% PRB use in the barged coal would provide combined fuel savings of $47M of CRN from 2007-2010. This does not take into account costs to use PRB.

2. **S&L Study: Romas Rupinskas of S&L** presented findings of their recent study. They looked at 3 levels of PRB use: <30%, 70% and 100% PRB. The study used a PRB/Illinois coal blend for conservatism. The < 30% PRB case is the one that is practical for CRN given the restricted barge capacity. [Economically, the PRB only makes sense if delivered via barge – rail is expensive.]

   It was noted that the original boiler design was based on 50% PRB and 50% CAP. However, design did not provide a full spare pulverizer per S&L's calculations; seems to be about 10%

to 15% short of full load coal flow rate on a design comparison basis with one pulverizer out of service.

Romas then discussed findings per component:

a. **Furnace** – large size. Is 15% larger than avg PRB boiler. Looks good.
b. **Convection pass** OK.
c. **Space exists for 7th mill & silo** (~~although do not think needed for~~not needed < 30% PRB unless one mill is out of service~~at this time.~~)
d. **Large ESP – looks good** – *this generated a lot of PGN comments:*
   i. ESPs have opacity issues since can only maintain every 18 months.
   ii. Rapper system needs repair. Arthur Spencer said estimate to replace side mounted with top mounted rappers is $30M/box. Romas stated that he knew of another utility with same CE ESP and side rappers that had report good success with ESP. Romas to forward contact info to Arthur S.
   iii. Opacity limit is 20% by permit, but 15% is limit to meet Compliance Assurance Monitoring (CAM). The CAM was based on the previous coals burned to date and did not account for PRB use. [Romas to check on which opacity used in calculations.]
   iv. If we lower FEGT, what does that do to ESP performance? – Bill Catsikopoulos (Bill C)
   v. Romas mentioned that SO3 conditioning system is a possible solution, if needed, to counter the low Sulfur in PRB.
e. **Cost Estimates** – were prepared for each of the 3 PRB cases. These estimates will be revised per meeting discussion.

3. **Plant Concerns:**

   a. **Spontaneous Combustion:** *Rufus and Bill C stated concern with spontaneous combustion issues.* Romas stated these should not be much more prevalent than existing issues with bituminous coal if we stay < 30% PRB. *Rufus said the plant has coal pile fires occasionally with their "D" coal – low sulfur.*

   b. **Mill Inerting:** *Titus S stated that current system is not very effective. Would like to see some improvements if we used PRB. Gary Labuda stated that steam inerting system is in place but not currently operational. Would need maintenance $ to fix prior to putting in service. Service water is also available to mills.* [Gary L: please provide an estimate for mill inerting repairs.]

   c. **Mill Performance/Capacity:**
      i. *There is a current 400° F* ***mill inlet temp limit.*** *This was imposed by the plant when they had a bad thermocouple once and mill caught fire. This limit would need to be increased if burned PRB. Bill Albright and Titus S can provide further details. Suggestion was made that B&W has reviewed this*

and S&L can contact them directly.–130° F min outlet temp. S&L has not seen mill inlet temperature limits this low for any PRB blend. 130F outlet is as low as we have seen.

ii. ***Mill throughput**: Plant questioned calculations that show can get full load @ 5% OP with 30% PRB. Stated that unit can make MDC with 11,700 Btu/lb Colombian coal but derates 27-30 MW when that coal is very wet. 11,400-11,600 Btu/lb Colombian will make 750 MW is its dry. Rufus gets concerned if MDC drops to 740Mw or less. Bill Stenzel (S&L) to talk with Titus S to resolve. [Post-meeting: Was determined that mill capacity test is the best way to determine current actual capacity.] S&L provided calculations that are an estimate of pulverizer capacity, which shows the 30% or less PRB is feasible, but without a spare pulverizer.*

iii. ***MDC Ability*** – Wayne Toms stated that need to be careful on any impacts to Commercial Availability since CRN is baseload. Consider trial in shoulder months.

d. **Dust Collectors:**

i. **Repair Existing:** For < 30% PRB, S&L proposed to have the existing (4) dust collectors repaired. *Dan Grannan stated these were beyond repair and that Fuel Handling was looking at new style dust collector for cascade room.* Romas stated that wet type dust collectors were priced for 70% PRB option (at $1.6M combined) and that might also need transfer point dust collection. [S&L to revise cost estimate accordingly, but note that this is something plant may be funding separately.]

e. Sootblowers: Sootblowers need to be operational to prevent additional propensity for slagging/fouling associated with PRB's lower AFT's. *It was estimated by Titus that approximately 40 IR's and 83 IK's either currently need or will soon need repair. This would be approx $1M to fix. Wayne Toms stated that approximately 74% of Unit 4's and 65% of Unit 5's sootblowers were currently operational and asked what level needed to be at for test burn.* [S&L to advise on what needed % of sootblower operation needed for <30% PRB test burn.]

f. **PA Fan Capacity:** *Jeff Swartz stated that they are almost PA fan limited when do cold startup, due to excessive Primary and Secondary A/H inleakage. But cold startup does not occur very often, since are baseloaded units. Titus stated that cold end seal adjustors could be added to assist with this. Jeff suggested looking at May 2005 data for last startup. It is S&L's understanding that leakage is reduced when the Rothemule PA reaches operating temperatures and there adequate PA flow.*

g. **PRB coal blend assurance:** *Bill C expressed concern about consistent blends and ensuring that do not receive higher % PRB than agreed upon.* Rob Reynolds stated that proper contracting and quality assurance measures would be taken.

h. **O&M Increases:** *Report stated that O&M increases with < 30% PRB were negligible. However plant feels that the following O&M increases would exist:*
   i. *Routine maintenance on new dust collection system – which is not currently being maintained.*
   ii. *Need to have better Sootblowing maintenance system. Not allow to go unfixed.*
   iii. *Might have increased cleaning due to higher slagging/fouling potential.* *Should not be a significant problem with the large furnace size. Again this boiler was designed for 50% PRB.*
   iv. *If dust suppression chemicals are needed, would increase O&M.*
   [Being revised in latest version of report.]

   However, pulverizer maintenance should be less. I

   It will be important to consider modifications to the pulverizers to achieve fineness, especially >50 mesh so that unburned carbon does not prevent flyash sale. This may require rotating classifiers, adjustable tensioning, larger grinding tables, coal pipe adjustments, air/coal pipe flow testing and adjustments and/or other modifications. The S&L cost estimate includes an allowance for what might be determined to be needed after detailed study.

   NOx should be less.

i. **Recoverability:** A question was raised about potential cost recoverability. Rob R mentioned that we have not approached Javier Portuondo on this issue yet. Once test is completed and the data/savings can be verified, RFD will work with Regulatory Accounting on appropriate options.

   Recoverability note from John Holler post-meeting, "On the pass-through issue, the costs for plant upgrades to allow us to burn PRB coals most likely won't be passed through the ECRC. Based on the discussion we had with Lori Cross and others that are on Javier Portuondo's staff regarding some of the issues for the FGD project (such as possibly needing to upgrade mills for lower BTU/lb Illinois Basin coals), the costs would more likely be submitted through the Fuel Adjustment clause, if at all. Lori is ~~meeting with~~ Javier today [9/30/05] to discuss the issues, and may be able to give us some better guidance shortly."

j. **Other utilities similar?**
   i. As part of the presentation, Dan D listed companies using PRB/CAPP blends, including Cinergy, DTE, First Energy, TVA and AEP. Duke Energy and Allegheny recently mentioned they were looking at test burns.
   ii. Bill C was interested in learning about DTE's Belle River plant's experience with PRB. He said they were similar to CRN units.
   iii. Romas stated that Allegany uses PRB blends at smaller units.

4. **Permitting: [Dave Meyer]**

a. **Test burn:** Group agreed that DEP and CRN would want to do a test burn (probably 20% PRB) for at least 1 week. Dave mentioned that talks had begun with DEP and that ESS was creating separate application for PRB so that it would be approved quicker than the Major Projects application.
b. **Timing:** The timing of the approval for trial burn could be anywhere from 4 – 9 months. [It was agreed that ESS, SE and RFD should get together soon and discuss permit path and timing. Talks have commenced post-meeting.]

5. **Action Items:**
   a. S&L to investigate the following and revise report accordingly:
      i. PA Fan Limit – temp to mills
      ii. Mill Capacity requirements
      iii. ESP – rapping system
      iv. New dust collectors
      v. Mill inerting for 30% case
   b. S&L to assemble list of minimum improvements needed to safely use < 30% PRB. Arrange in list of previously proposed plant projects vs. new PRB-related project.
   c. Regulated Fuels/SE to arrange meeting with ESS to discuss PRB permitting strategy. [Began 10/5 conf call.] Meanwhile ESS to continue on path of separate permit submittal.
   d. Dan D to reissue S&L report with new cost estimates.
   e. Plant to advise on % sootblowers can get operational by spring 2006.

6. **Future Items:**
   a. Dan D & Michael R to attend Charlie Gates 10/27 Manager's Meeting and provide PRB update.
   b. Discussion to be held with Charlie G, Jack K and Mike W on 10-24-05.

Discussion lasted from 1300-1500.

Exhibit ____ (RS-23)

FDEP Excerpts From Power Magazine

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Draft Air Construction Permit No. 0170004-012-AC
Progress Energy - Crystal River Power Plant
Powder River Basin Coal Blend Trial Burn

COUNTY

Citrus County, Florida

APPLICANT

Progress Energy Florida, Inc.
Crystal River Power Plant
100 Central Avenue, CN77
St. Petersburg, FL 33701

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Air Permitting North Program

April 4, 2006

{Filename: TEPD - 0170004-012-AC}

1. GENERAL PROJECT INFORMATION

Facility Description and Location

Progress Energy operates the existing coal-fired Crystal River Power Plant (SIC No. 4911), which is located on Power Line Road north of Crystal River and west of U.S. Highway 19 in Citrus County, Florida. The UTM coordinates are Zone 334.3 km East, and 32.04.5 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). This facility consists of: four coal-fired fossil fuel steam generating units with electrostatic precipitators; two natural draft cooling towers for Units 4 and 5; helper mechanical cooling towers for Units 1, 2 and Nuclear Unit 3; ash-handling facilities, and relocatable diesel-fired generators.

Regulatory Categories

Title III: The facility is a major source of hazardous air pollutants (HAP).

Title IV: The facility operates units subject to the acid rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Rule 62-212.400, F.A.C.

NSPS: The facility operates units subject to the New Source Performance Standards of 40 CFR 60.

Project Description

Units 4 and 5 are dry-bottom, wall-fired units manufactured by Combustion Engineering and each rated at 760 MW with a maximum heat input rate of 6665 MMBtu per hour. The units are authorized to fire bituminous coal, a bituminous coal and bituminous coal briquette mixture, used oil, No. 2 fuel oil as a startup fuel, and natural gas as a startup and low-load flame stabilization fuel. Exhaust gases from each unit exit a stack that is 600 feet tall.

On March 6, 2006, the Department received an application requesting a trial burn for a blend of up to 30% sub-bituminous Powder River Basin coal (PRB) with existing bituminous coal. The plant proposes to burn 9-10 barge loads of blended coal (approximately 150,000 tons, total) in Units 4 and 5. A variety of blends may be tested. The two coals will be blended off-site and shipped to the plant as a premixed blend.

Each boiler could fire approximately 300 tons of PRB coal blend based on: a blend of 70% bituminous coal with 30% PRB coal; a heating value of 11,117 Btu/lb; and the maximum heat input rate for the unit. The proposed amount of PRB coal blend would be fired for approximately 250 hours per boiler at full load conditions. At this rate, it would take approximately 11 days with both boilers operating at full load to burn the entire PRB coal blend. The applicant proposes a 90-day trial burn period to provide flexibility for the testing schedule and barge deliveries.

The applicant indicates that the firing of the proposed PRB coal blend will likely result in: CO and VOC emissions comparable to current coal firing; SO_2 emissions comparable or lower than current coal firing; NOx emissions comparable or lower than current coal firing; and PM/PM_{10} emissions comparable to current coal firing (fugitives addressed by off-site blending).

The plant will continue to comply with all conditions of the current Title V air operation permit. For the duration of the trial burn, COMS/CEMS data will be monitored and recorded for opacity as well as NOx and SO_2 emissions. An emissions test (EPA Method 5 or 17) will be conducted for particulate matter emissions. Daily records of the of the boiler operations when firing the PRB coal blend will be maintained and reported (i.e., fuel firing rates and heat input rates). If the trial burn results in operation not in accordance with the conditions of the permit or test protocol, the performance testing will cease as soon as possible. The trial burn will not resume until appropriate actions have been taken to correct the problem. A test report will be submitted within 45 days of completing the trial burn.

2. APPLICABLE REGULATIONS

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review, PSD Review and BACT, and Non-attainment Area Review and LAER); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures).

Federal Regulations

This project will not impose or revise any applicable federal regulations.

General PSD Applicability

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as approved by the EPA in Florida's State Implementation Plan and defined in Rule 62-212.400, F.A.C. A PSD review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for a given pollutant. A new facility is considered "major" with respect to PSD if it emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant, or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD Major Facility Categories, or 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates defined Rule 62-210.200, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants.

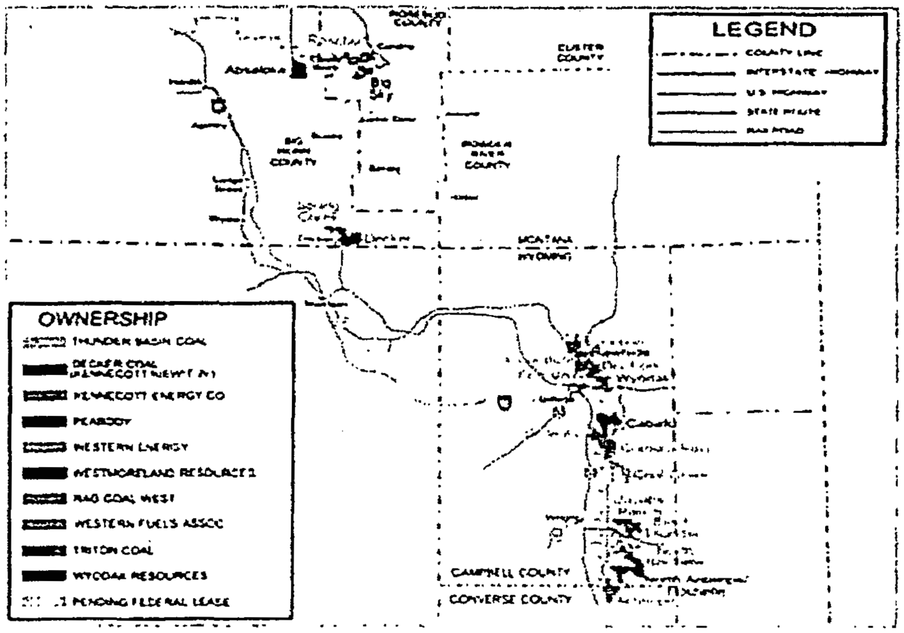
3. DEPARTMENT REVIEW

What is "Powder River Basin (PRB)"coal?[1]

Powder River Basin (PRB) coal is named after the geographic region where it is mined. It includes parts of southeast Montana and northeast Wyoming and covers about 120 miles east-to-west and 200 miles north-to-south. The basin is so named because it is drained by the Powder River. The area consists of rolling grasslands with an arid climate and is sparsely populated. Figure 3.1 on the following page shows a general map of this region.

The Powder River Basin is one of the largest sources of coal mined in the United States. The relatively low sulfur and ash content of PRB coal makes it popular. In recent years, over 350 million tons of coal have been mined annually. Much of the PRB coal is transported by rail to fire power plants in the Midwest. Table 3A on the following page compares the proximate and ultimate analyses of an Appalachian coal with those of a blend of 30% PRB coal / 70% Appalachian coal.

Figure 3.1 Powder River Basin. (Power Magazine; Oct. :



Courtesy: RAG American Coal Holding Inc.

Table 3A. Coal Analyses (As Received) [2]

Parameter	Appalachian Coal	PRB Coal	70% / 30% PRB Coal Blend
Proximate Analysis			
% Moisture	7.97	26.47	13.52
% Ash	10.25	6.12	8.91
% Volatile Matter	28.83	39.47	32.89
% Fixed Carbon	52.91	27.94	44.68
Ultimate Analysis			
% Moisture	7.97	26.47	13.52
% Carbon	65.14	49.47	61.16
% Hydrogen	4.66	3.67	4.4
% Nitrogen	0.98	0.69	0.89
% Chlorine	0.08	0.01	0.06
% Sulfur	0.73	0.24	0.56
% Ash	10.25	6.12	8.91
% Oxygen	10.19	12.83	10.50
Heating Value, Btu/lb	12,239	8692	11,117
Trace Metals			
Arsenic, ppm	3.39	0.25	2.45
Lead, ppm	6.41	1.11	4.82
Mercury, ppm	0.10	0.02	0.08

What are the disadvantages of firing PRB coal? [1]

Compared to most eastern coals, PRB coal: has a higher moisture content; is more friable; has a lower heating value per pound; and has a lower ash-softening temperature. These characteristics generally mean more fouling and slagging of the boiler surfaces as well as fugitive dust and fire control problems. Some of these problems may be mitigated by the relatively low blending rates proposed in the application. However, some blended coals may have chemical interactions leading to corrosion and additional tube wastage.

What are the advantages of firing PRB coal? [1]

As shown above in Table 3A, PRB coal often contains lower sulfur, which can be beneficial when trying to lower sulfur dioxide emissions. In addition, the higher moisture content may help to lower NOx emissions. However, the main attraction is the much lower cost, even considering that PRB coal must be transported long distances from it origin. The following figure provides a "delivered cost" comparison with other coals.

Figure 3.2 2002 Average Prices and Specifications of Coal Delivered to Eastern Utilities
(Power Magazine; October 2003)

Table 2. 2002 average prices and specs of coal delivered to eastern utilities

Main region	Delivered cost, $/mmBtu	Heating value, Btu/lb	Sulfur content, lb/mmBtu
Central Appalachia	1.53	12,414	1.49
Southern PRB	1.064	8,763	0.61
Illinois Basin	1.12	11,262	4.40
Northern Appalachia: Northeast	1.16	12,532	3.67
Northern Appalachia: Ohio	1.103	11,997	5.57
Southern Appalachia	1.62	12,071	2.06
Central Rockies	1.474	11,872	0.94

As shown in the above table, the delivered cost of PRB coal is approximately 30% less than other western coals and approximately 35% less than some eastern coals.

What are the expected emissions impacts from firing PRB coal?

The plant currently fires an eastern Appalachian coal, which is a bituminous coal. PRB coal is a subbituminous coal. To estimate impacts from the trial project, the Department used standard EPA emission factors for bituminous and subbituminous coals. The following table provides a comparison summary of the expected emissions. For full details of the comparison, see the Attachments at the end of this Technical Evaluation and Preliminary Determination.

Table 3B. Emissions Comparison

Pollutant	lb/ton		lb/hour		lb/MMBtu		tons/trial		Difference
	Bit.	Blend	Bit.	Blend	Bit.	Blend	Bit.	Blend	tons/trial
CO	0.50	0.50	136.1	149.9	0.020	0.022	34.1	37.5	3.4
NOx	12.00	10.62	3267.4	3183.5	0.490	0.478	817.5	796.5	-21.0
PM	0.82	0.79	223.3	235.9	0.033	0.035	55.9	59.0	3.1
PM_{10}	0.20	0.19	54.5	57.3	0.008	0.009	13.6	14.3	0.7
SO_2	27.70	25.27	7542.3	7575.1	1.132	1.137	1887.0	1895.3	8.3
VOC	0.06	0.06	16.3	18.0	0.002	0.003	4.1	4.5	0.4

Notes:

1. Emissions are based on EPA's general emission factors for firing bituminous and subbituminous coals in dry bottom, wall-fired boilers. See Tables 1.1-3, 1.1-4, 1.1-19 in EPA's emission factor reference document (AP-42).[3]
2. PRB coal blend consists of 30% subbituminous coal and 70% bituminous coal.
3. Total emissions from the project (tons/trial) are based on firing 150,000 tons of PRB blended coal.[2]
4. For comparison purposes, an equivalent amount of bituminous coal based on representative heating values would be 136,249 tons.

Based on these "average" emissions factors, the predicted differences in actual emissions are very small and impacts from the temporary project will be minimal. The estimated emissions increased will be well below the PSD significant emissions rates. Therefore, the project is not subject to PSD preconstruction review.

Conclusion

The applicant's request for a temporary trial burn to gather emissions and operational data is acceptable and is not reasonably expected to result in PSD-significant emissions increases. The draft permit includes the following requirements:

- Provide a preliminary schedule for conducting the trial burn.
- Record the amount and blend ratio of PRB coal blend delivered.
- Retain a "certificate of analysis" for each shipment (proximate and ultimate analysis).
- Take actual samples of the PRB coal blend and analyze (proximate and ultimate analyses).
- Finish trial burn within 90 days of initial firing of the PRB coal blend.
- Fire no more than 150,000 tons of PRB coal blend during the authorized trial burn period.
- Comply with all requirements in current Title V air operation permit. If the trial burn results in operation not in accordance with the conditions of the permit or test protocol, the performance testing will cease as soon as possible. The trial burn shall not resume until appropriate actions have been taken to correct the problem.
- Conduct emissions tests for each boiler at permitted capacity (3 runs each) to determine CO and particulate matter emissions when firing the blend with the highest PRB coal percentage delivered during the trial burn. VOC emissions are typically very low for these types of units and VOC tests will not be required. Instead, CO emissions test data will provide information on the relative combustion efficiency of the units.
- Maintain records of the daily boiler operations when firing the PRB coal blend (i.e., fuel firing rates and heat input rates).
- Continuously monitor and record opacity, NO_x emissions, and SO_2 emissions with existing monitoring systems when firing the PRB coal blend.
- Sample and analyze fly ash resistivity for baseline versus PRB coal firing. (Different coals have different compositions, which can lead to changes in fly ash resistivity. In turn, this can result in less control of particulate matter from an existing electrostatic precipitator.)
- Evaluate the performance of the existing electrostatic precipitators (ESPs). Monitor the total ESP secondary power input. Identify any adjustments or improvements that may be necessary.
- For comparison purposes, identify the current corresponding baseline monitoring values (for firing only bituminous coal) or collect baseline data during the trial burn period.
- Submit of a final report summarizing the trial burn.

4. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

5. REFERENCES

[1] Article, "Burning PRB Coal", by Dr. Robert Peltier, P.E. and Ken Wicker, POWER Magazine (powermag.platts.com), October 2003.

[2] Air Permit Application No. 0170004-012-AC, Progress Energy Florida, Inc.'s Crystal River Power Plant, Request for Trial Burn to Fire Powder River Basin Coal Blended with Appalachian Coal, March 2006.

[3] "Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources (AP-42)", Section 1.1 Bituminous and Subbituminous Coal Combustion (dry bottom, wall-fired boilers), U.S. Environmental Protection Agency, September 1998.

Exhibit ____ (RS-24)

2004 Bids Delivered to Crystal River Units 4 and 5

2004 Bids For 2005/2006/2007
Delivered To Crystal River 4/5

	$/MMBTU
PRB	1.87
Imports	2.52-2.87
CAPP Non-Affiliate	2.67
CAPP/Synfuels Affiliate	Not Bid

Exhibit ____ (RS-25)

Trade Press on PEF's Coal Solicitations

Coal Solicitations

Utility	Plant	Tonnage	Term	Bids Due	Status
Allegheny Power	Harrison	Unspecified	2005	7/7/04	Still evaluating bids
American Electric Power	System-wide	At least 10K/month	2005-2009	8/27/04	Pending
Ames, City of	Ames	290K tons/yr	5 years, start 9/04	2/13/04	Pending
DTE Energy Services	Mobile Energy Services plant	At least 25K/yr	2005-2012	8/24/04	Pending
East Kentucky Power Coop	Dale & Cooper	25K tons/month	Q4 2004	8/27/04	Pending
East Kentucky Power Coop	New Gilbert unit @ Spurlock	50K tons/month	Q4 2004	4/9/04	Pending
East Kentucky Power Coop	New Gilbert unit @ Spurlock	50K tons/month	Up to 10 yrs	6/18/04	Pending
East Kentucky Power Coop	Spurlock unit 1	25K tons/month	Up to 10 yrs	6/18/04	Pending
East Kentucky Power Coop	Dale	Up to 20K tons/month	Up to 5 yrs	6/30/04	Pending
East Kentucky Power Coop	Cooper	Up to 20K tons/month	Up to 10 yrs	6/30/04	Pending
Energy Services Group	Various	1.2mn tons/yr	2004-2005	5/28/04	Negotiations continue
FirstEnergy	Ashtabula, Oregon, Eastlake, Lake Shore	500,000-2mn tons/yr	2005-2010	—	Pending
Holcim Cement	System-wide	More than 1mn tons	2005	6/11/04	Pending
Kentucky Utilities	Brown & Tyrone	Unspecified	Up to 5 yrs, start '04	3/23/04	Close to completion
Louisville Gas & Electric/Kentucky Utilities	Various	Unspecified	Unspecified	5/12/04	Close to completion
Nova Scotia Power	Unspecified	At least 300K mt/yr	2005 and beyond	9/9/04	—
Orlando Utilities Commission	Stanton	Up to 264K tons	2005-2006	7/9/04	Pending
Progress Energy	Crystal River	At least 300K tons/yr	2005-2007	5/12/04	Pending
Progress Energy	System-wide	Up to 1.6mn tons/yr	Up to 3 yrs	6/30/04	Pending
Rochester Gas & Electric	Russell	Up to 200K tons/yr	2004-2007	5/14/04	Pending
Seminole Electric Coop	Seminole	100K	2004	8/6/04	Still evaluating bids
Seminole Electric Coop.	Seminole	up to 600K/yr	2005-2006	8/20/04	Pending
Southern Co. Services/Georgia Power	NS plants (Max 1.5% sulfur)	Up to 1mn tons/yr	2005-2007	8/16/04	Pending
Southern Co. Services/Georgia Power	NS plants (Max 2.8% sulfur)	Up to 1mn tons/yr	2005-2007	8/16/04	Pending
Southern Co. Services/Georgia Power	CSX plants	At least 500K tons/yr	2005-2010	7/26/04	Pending
Southern Co. Services/Georgia Power	CSX plants	Up to 1mn tons	2005	7/26/04	Pending
Southern Co. Services/Georgia Power	CSX plants	At least 500K tons/yr	2005-2010	4/27/04	Still evaluating bids
Southern Co. Services/Savannah Electric & Power	Kraft and McIntosh	Up to 400K tons/yr	2005-2006	6/4/04	Pending
Springfield, Mo. City Utilities	James River and Southwest	More than 1mn tons	2005-2007	6/2/04	Pending
Tennessee Valley Authority	Various	Up to 11.5mn tons/yr	up to 10 yrs	4/30/04	Pending

could start exporting met coal by next year, said Alberto Jimenez, the port's general manager.

"We presented our project 11 months ago and we have not heard from the Transport Ministry yet. I hope we obtain the permission by the year's end," Jimenez said. Investment requirements for coal export facilities would be minimal, since the port already has storage capability.

But the project is facing fierce opposition.

Cartagena authorities are claiming that the 471-year-old city, considered a worldwide historical heritage city by Unesco, would suffer environmental damage by allowing met coal exports from the port.

Jimenez explained that coking products are much more environmental friendly than regular coal and will not harm historic Cartagena. Fenalcarbon, the Colombian federation of coal, has said that if the Transportation Ministry places too many demands on Muelles del Bosque in light of local opposition, the port may not be able to start exports of coal for up to several years.

Muelles del Bosque exported 300,000 tons last year from steel to food products.

Colombia has more than 654 mines in the inland states of Cundinamarca, Boyaca and Norte de Santander of high caloric value steam coals and coking coals, which are currently exported mainly through the Santa Marta port.

Coal Solicitations

Utility	Plant	Tonnage	Term	Bids Due	Status
Allegheny Power	Unspecified	Unspecified	2005	10/31/04	—
Allegheny Power	Harrison	Unspecified	2005	7/7/04	Still evaluating bids
American Electric Power	System-wide	At least 10K/month	2005-2009	8/27/04	Pending
Constellation (imported & domestic)	Baltimore plants	Up to 450K mt/year	2005-2007	9/14/04	Pending
Constellation (Central App)	Baltimore plants	Up to 1mn tons/yr	2005-2007	9/14/04	Pending
Dan River Mills	Danville & Brookneal	40K	Unspecified	—	—
Dominion	System-wide	At least 10K/month	3-24 months, start 1/05	8/30/04	Pending
DTE Energy Services	Mobile Energy Services plant	At least 25K/yr	2005-2012	8/24/04	Pending
East Kentucky Power Coop	Dale & Cooper	25K tons/month	Q4 2004	8/27/04	Pending
East Kentucky Power Coop	New Gilbert unit @ Spurlock	50K tons/month	Q4 2004	4/9/04	Pending
East Kentucky Power Coop	New Gilbert unit @ Spurlock	50K tons/month	Up to 10 yrs	6/18/04	Pending
East Kentucky Power Coop	Spurlock unit 1	25K tons/month	Up to 10 yrs	6/18/04	Pending
East Kentucky Power Coop	Dale	Up to 20K tons/month	Up to 6 yrs	6/30/04	Pending
East Kentucky Power Coop	Cooper	Up to 20K tons/month	Up to 10 yrs	6/30/04	Pending
Energy Services Group	Various	1.2mn tons/yr	2004-2005	5/28/04	Negotiations continue
FirstEnergy	Ashtabula, Oregon, Eastlake, Lake Shore	500,000-2mn tons/yr	2005-2010	—	Pending
Holcim Cement	System-wide	More than 1mn tons	2005	6/11/04	Pending
Louisville Gas & Electric/Kentucky Utilities	Brown & Tyrone	Unspecified	Up to 5 yrs, start '04	3/23/04	Close to completion
Louisville Gas & Electric/Kentucky Utilities	Various	Unspecified	Unspecified	5/12/04	Close to completion
New Brunswick Power	Belledune	1.2mn mt/yr	May 2005 to Dec. 2006	9/22/04	—
Nova Scotia Power	Unspecified	At least 300K mt/yr	2005 and beyond	9/9/04	Pending
Orlando Utilities Commission	Stanton	Up to 264K tons	2005-2006	7/9/04	Pending
Progress Energy	Crystal River	At least 300K tons/yr	2005-2007	5/12/04	Pending
Progress Energy	System-wide	Up to 1.6mn tons/yr	Up to 3 yrs	6/30/04	Pending
Rochester Gas & Electric	Russell	Up to 200K tons/yr	2004-2007	5/14/04	Pending
Santee Cooper	CSX plants	Up to 840K tons/yr	2005-2009	9/29/04	—
Seminole Electric Coop	Seminole	100K tons	2004	8/6/04	Still evaluating bids
Seminole Electric Coop.	Seminole	up to 600K tons/yr	2005-2006	8/20/04	Pending
South Carolina Electric & Gas	System-wide	Up to 500K tons/yr	2005-2008	—	Pending
Southern Co. Services/Georgia Power	NS plants (Max 1.5% sulfur)	Up to 1mn tons/yr	2005-2007	8/16/04	Pending
Southern Co. Services/Georgia Power	NS plants (Max 2.8% sulfur)	Up to 1mn tons/yr	2005-2007	8/16/04	Pending
Southern Co. Services/Georgia Power	CSX plants	At least 500K tons/yr	2005-2010	7/26/04	Pending
Southern Co. Services/Georgia Power	CSX plants	Up to 1mn tons	2005	7/26/04	Pending
Southern Co. Services/Savannah Electric & Power	Kraft and McIntosh	Up to 400K tons/yr	2005-2006	6/4/04	Pending
Springfield, Mo. City Utilities	James River and Southwest	More than 1mn tons	2005-2007	6/2/04	Pending
Tampa Electric	Big Bend and Polk	100K tons for Q4 and 1.5mn tons for 2005	Q4 2004 and 2005	10/4/04	—
WPS	Escanaba	150K tons	Q4 2004	9/14/04	Pending

Exhibit ____ (RS-26)

"Overcharges" to PEF Ratepayers: 1996-2005

Exhibit ___ (RS-26)
Page 1 of 1

Excess Costs Of Coal And Extra SO2 Allowances Resulting From Failure To Blend PRB Subbituminous Coal With Bituminous Coal In Crystal River Units 4 And 5 (1996-2005)

Year	Excess Coal Costs $	Excess SO2 Allowance Cost $	Total Excess Fuel Charges $
1996	1,056,000	N/A	1,056,000
1997	5,617,376	N/A	5,617,376
1998	7,703,136	N/A	7,703,136
1999	8,412,664	N/A	8,412,664
2000	4,884,739	1,497,278	6,382,017
2001	14,923,313	1,897,541	16,820,854
2002	20,712,248	1,410,049	22,122,297
2003	14,108,871	1,413,510	15,522,381
2004	17,603,768	4,196,799	21,800,567
2005	21,572,511	7,513,540	29,086,051
Total w/o Interest	**116,594,626**	**17,928,717**	**134,523,343**

Assumptions and note:

(1) 1996, PRB 500,000 tons total tonnage: 1997-2005, PRB = 50% of total tonnage.

(2) Btu's obtained from PRB coal are 40% of total Btu's purchased for Crystal River Units 4 and 5 during years in which 50/50 blend is assumed.

(3) Actual delivered cost of fuel for Crystal River Units 4 and 5 delivered to IMT as reported by PEF to FERC compared to corresponding delivered cost of PRB subbitumnious coal delivered to TECO's New Orleans dock (for 1996-2002) adjusted for blending cost, with an across-Gulf freight penalty to PRB coal because of its lower heating value vs. bituminous coal. For 2003 a Southeast delivered PRB price escalation was applied to the 2002 TECO PRB deilvered price. For 2004-2005 bids received by PEF solicitation were used.

(4) Reflects cost of SO2 allowances that would have been saved by PRB blend, valued at market value that prevailed at the time.

(5) Interest not included in calculations.

Exhibit ____ (RS-27)

Overcharges Methodology

Fuel Damages Summary

Year	(1) Total CAPP Tons CR 4/5 MMT	(2) Total CR 4/5 10^6 MMBTU	(3) PRB MMBTU $x10^6$	(4) PRB Tons MMT	(5) $/MMBTU CAPP	(6) $/MMBTU PRB	(7) Delta $/MMBTU	(8) Damages Revised $ 000's
1996	3.5	87.5	8.8	0.50	1.71	1.42	0.12	1,056
1997	4.0	100.0	40.0	2.30	1.73	1.41	0.14	5,617
1998	3.7	92.5	37.0	2.12	1.73	1.34	0.21	7,703
1999	3.7	92.5	37.0	2.10	1.67	1.26	0.23	8,413
2000	3.7	92.5	37.0	2.10	1.64	1.34	0.13	4,885
2001	3.6	40.0	36.0	2.06	2.03	1.42	0.42	14,923
2002	3.2	80.0	32.0	1.82	2.19	1.36	0.65	20,712
2003	3.2	80.0	32.0	1.82	2.10	1.46	0.43	14,109
2004	3.7	42.5	37.0	2.11	2.33	1.87	0.46	17,604
2005 (9)	3.4	85.9	34.3	1.95	2.13	1.47	0.68	21,572
							Total Without Interest	**116,595**

Notes: See attached discussion of issuse.
(1) From FERC 423 CR 4/5 tons by railroad to IMT.
(2) Col (1) x 25 MMBTU/ton CAPP coal (refine).
(3) Col (2) x 40%.
(4) Col (3) divided by MMBTU/ton of TECO PRB coal.
(5) $/MMBTU of CAPP coal to IMT for CR 4&5.
(6) Based on $/MMBTU PRB to ECT by TECO.
(7) Delta is Col (5) minus [Col (6) + 11 to 16 cents/MMBTU + 4 cents/MMBTU].
(8) Col (7) times Col (3).
(9) For 2005 an adjustment is made for a 7.5% PRB delivery shortfall.

Docket No. 060658
Testimony of OPC witness Sansom
Exhibit No. __ (RS-27)
Page 1 of 3

DAMAGES METHODOLOGY

(1) Blend ratio is 50/50 on a tonnage basis. Since BTU of CAPP is ratio of 4&5 CAPP BTU (Rail & IMT) and PRB.

PRB BTU:

$$\frac{8{,}800}{8{,}800 + 12{,}500} = \frac{8{,}800}{21{,}300} = 41.3\%$$

Orig. B&V Spec was 12,450 CAP 8,125 PRB.

$$\frac{12{,}450}{12{,}450 + 8{,}125} = 60\%\text{ CAPP}$$

So use 40% of BTUs from PRB.

(2) For PRB price use for years available (1996-2002) the TECO to ECT price of PRB Coal for Gannon, adjust by Ocean Barge Rate for lower BTU Coal to CR 4&5 using PEF barge rate for the appropriate year. For example:

$$\text{CAPP} \quad \frac{8.00}{25\text{ MMBTU}} = 32.0¢/\text{MMBTU}$$

$$\text{PRB} \quad \frac{8.00}{8800 \times 2} = \underline{45.5¢/\text{MMBTU}}$$

$$\Delta = 13.5¢/\text{MMBTU}$$

(3) So take dlvd CR 4&5 price to IMT minus delivered PRB Price to ECT and from this difference subtract 13.5¢ to Credit CAPP for lower Ocean Barge Transport Cost in ¢/MMBTU.

(4) Tonnage of PRB is 40% of total CAPP dlvd BTU's to CR 4&5 as shown by FERC 423 CR 4&5 tons by rail to CR plus tons by barge to IMT. To convert to PRB tons I use BTU/lb value of Gannon PRB to ECT. For 1996 I start with 500,000 tons of PRB. After the PRB BTU's are 40% of deliveries for CR 4/5.

(5) For 2003 PRB I used 2002 Gannon price to ECT plus 10¢/MMBTU considering change in dlvd PRB to Scherer '03 vs. '02 was + 6¢, to Miller + 14¢, i.e., 14¢ + 6¢/2 = 20/2 = 10¢/MMBTU. For 2004 and 2005 I used 2nd lowest PRB bid received by PEF in May 2004 minus adjustment to convert price from dlvd to CR 4&5 at $1.87/MMBTU, as follows:

$$\frac{\$7.00}{8{,}000 \times 2} = 40.0¢$$

So $1.87 – 0.40 = $1.47/MMBTU to IMT.

(6) Barge Unloading Capacity: Late 1980's FPC Plot Drawing for CR shows Barge Unloading Capacity of 2.3 MMTPY at CR. All CR 1&2 Coal comes in by rail. Barge Unloading Rate may have been increased. Pitcher Depo p.22 said Ocean Barge Capacity =2.5 MMTPY max tons to IMT were 2.4 MMT in 2001.

(7) Other options are PRB Rail to CR and PRB to McDuffie Terminal at Mobile which makes backhaul by Dixie to Holcium easier and turnarounds quicker. BNSF Rail Rate to Mobile or UP CN (IC) could be low. PEF data show about 75¢/ton lower Ocean Barge Rate from McDuffie vs. IMT. Dixie has taken EFC FPC imports via McDuffie. Blending is available at McDuffie, which is served by NS and CSX, the railroads that originate CAPP coal.

(8) CR 4&5 was designed to blend with two Stacker Reclaimers. PRB by barge could be blended with bituminous by rail on delivery and on reclaim.

(9) I added a blending cost for PRB use. Using IMT rate of $2.50/ton for blending and 1.80 for non-blending transfer, blend cost is 70¢/ton or 4¢/MMBTU.

Exhibit ____ (RS-28)

1976 "Bituminous" Coal Permit Application to FDEP

Attachment D

Excerpt, 1996 Application for Title V "Air Permit" (Proposed Fuels for Crystal River Units 4 and 5)

B. GENERAL EMISSIONS UNIT INFORMAT...
(Regulated and Unregulated Emissions Units)

Attachment D

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Fossil Fuel Steam Generator Unit 4		
2 Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown 004		
3. Emissions Unit Status Code: A	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: 49
6. Emissions Unit Comment (limit to 500 characters): Pulverized coal dry bottom boiler, wall-fired.		

Emissions Unit Information Section 3 **of** 14

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Bituminous coal	
2. Source Classification Code (SCC): 1-01-002-02	
3. SCC Units: Tons Burned	
4. Maximum Hourly Rate: 277.7	5. Maximum Annual Rate: 2,432,725
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.7	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 24	
10. Segment Comment (limit to 200 characters): 1. Heat content based on 12,000 Btu/lb. 2. Maximum sulfur content based on SO2 emission limit of 1.2 lb/MMBtu; Condition of Certification for Units 4 and 5	

ATTACHMENT CR-E03-L2

FUEL ANALYSIS
COAL

Parameter	Value
Moisture content (%)	7.1
Ash content (%)	8.3
Sulfur content (%)	0.7 (maximum)
Heat content (Btu/lb)	12,200 (minimum) 13,200 (maximum)

Note: This coal is burned in Units No. 4 and 5. Except where noted, the values listed are general or typical values based upon information obtained from the suppliers. The coal is supplied by approximately 4 suppliers in eastern Kentucky, Virginia, and West Virginia.

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: EU4, See CR-FI-E2	
2. Emission Point Type Code: [x] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): Pulverized coal dry bottom boiler, wall-fired	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W	
6. Stack Height:	600 feet
7. Exit Diameter:	25.5 feet
8. Exit Temperature:	253 °F

Emissions Unit Information Section 4 **of** 14

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Bituminous coal	
2. Source Classification Code (SCC): 10100202	
3. SCC Units: Tons burned	
4. Maximum Hourly Rate: 277.7	5. Maximum Annual Rate: 2,433,725
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.7	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 24	
10. Segment Comment (limit to 200 characters): 1. Heat content based on 12,000 Btu/lb. 2. Maximum sulfur content based on SO2 emission limit of 1.2 lb/MMBtu; Condition of Certification for Units 4 and 5	

Exhibit ____ (RS-29)

PEF's Failure to Seek a Title V Permit to Continue

Crystal River Units 4 and 5's Environmental Authority

to Burn Sub-Bituminous Coal

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 060001-EI

Dated: June 2, 2006

PROGRESS ENERGY FLORIDA'S RESPONSES TO OPC'S FOURTH SET OF INTERROGATORIES (Nos. 25-27)

Progress Energy Florida, Inc., ("PEF" or "Company"), responds to OPC's Fourth Set of Interrogatories (Nos. 25-27), as follows:

GENERAL RESPONSES AND OBJECTIONS

PEF incorporates and restates its General Responses and Objections to OPC's Fourth Set of Interrogatories (Nos. 25-27), served on May 3, 2006, as if those responses and objections were fully set forth herein.

INTERROGATORIES

25 (a) When PEF first applied for its Title V Air Permit, did PEF—either in meetings with representatives prior to the filing of its application, or in the application itself—propose a scope of permitted authority that would allow PEF to burn sub-bituminous coal in Crystal River Units 4 and 5?

(b) If you answer (a) in the affirmative: Did PEF consciously decide at some point to modify its request so as to exclude the burning of sub-bituminous coal from the scope of the permit it sought?

(c) If you answer (b) in the affirmative, please identify the point at which PEF modified the scope of the permit to exclude the burning of sub-bituminous coal and explain why PEF took this step.

(d) During the course of the application process, to include any pre-application conferences and negotiations and including the issuance of the final permit(s), did either the Florida Department of Environmental Protection (referring here to its predecessor agency) or the federal Environmental Protection Agency indicate opposition to a scope of permit that would allow PEF to burn sub-bituminous coal at Crystal River Units 4 and 5 (assuming applicable emissions limits were to be met)? If you answer in the affirmative, please state the circumstances of any such communication of opposition, identify the persons involved, and identify all documents that reflect such a communication.

(e) From the time the final air permit was issued for Crystal River Units 4 and 5 to and including the present, has either the Florida Department of Environmental Protection (including its predecessor agency) or the federal Environmental Protection Agency indicated opposition to the interpretation of permit language that would authorize the burning of sub-bituminous coal at Crystal River Units 4 and 5? Did either agency (or predecessor agency) indicate opposition to the burning of sub-bituminous coal? If you answer in the affirmative, please identify the time when such communications were made; the persons who made and received them; a description of the circumstances; and identify all documents that comprise, discuss, or refer to such communications.

(f) If you answer (b) in the negative, was it PEF's position and belief during the application process that it had requested a scope of air permit that would authorize the burning of sub-bituminous coal at Crystal River Units 4 and 5? If so, prior to the decision to halt the 2004 test burn, did anyone within or outside PEF ever challenge or question PEF's authority, under the terms of its air permit, to burn sub-bituminous coal at Crystal River Units 4 and 5? In your answer, please provide details regarding the point in time when any such positions were expressed; the names of the persons making and receiving such communications; a description of the circumstances; and identify all documents comprising, discussing, or referring

Answer:

(a) The Emission Unit Information section of the Title V permit application lists "bituminous coal" as the proposed fuel. At the time of the application in 1996, PEF did not specifically contemplate or request approval to burn sub-bituminous coal.

(b) No.

(c) N/A.

(d) During the application process, approval to burn sub-bituminous coal was not specifically addressed by PEF or the reviewing agencies.

(e) Neither the DEP nor EPA has expressed support for burning sub-bituminous coal at CR4 or CR5 or a different interpretation of the Title V Permit. Dave Meyer (with PEF) attended a conference on November 15, 2005 titled "Title V Changes and Permit Modifications". The presentation was given by Scott Miller with EPA region 4. Dave Meyer asked Mr. Miller how the Title V permit could be modified to allow combustion of a sub-bituminous coal blend, given its present wording. Mr. Miller indicated that PEF would need to seek an amendment to the permit; however, Mr. Miller stated that as the Title V program is administered by the state of Florida, PEF should discuss this with the state.

On February 10, 2006 PEF and DEP representatives met to discuss combustion of a sub-bituminous coal blend. The state recommended that PEF submit a construction permit application to allow a test burn of a sub-bituminous coal blend. In attendance at the meeting were Scott Osbourn (with Golder & Associates), Dave Meyer and Jamie Hunter (Jamie by phone) (both with PEF). To our knowledge in attendance from FDEP were to Trina Vielhauer, Al Linero, and Jeff Koerner. Documents regarding these communications were produced in PEF's response to OPC's Second Request for Production of Documents, question #18.

(f) While PEF's records do not indicate what the individuals' beliefs were in the late-1970s, PEF's subsequent course of conduct indicates that the company did not believe it could burn sub-bituminous coal at CR 4 & 5. See also PEF's response to OPC's 1st Set of Interrogatories Question #7.

26. What does PEF estimate the percentage of removal of sulfur by ash to be for bituminous coal? For sub-bituminous coal?

Answer:

The EPA publishes a document called AP-42 which lists emission factors for various industries. The following is an excerpt from AP-42 1.1 Bituminous and Subbituminous Coal Combustion:

1.1.3.2 Sulfur Oxides4 -
Gaseous SO_x from coal combustion are primarily sulfur dioxide (SO_2), with a much lower quantity of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal are oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal will be emitted as gaseous SO_x, whereas somewhat less will be emitted when subbituminous coal is fired. The more alkaline nature of the ash in some subbituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the boiler or in the flyash.

Footnote for table 1.1-3:
Expressed as SO_2, including SO_2, SO_3, and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, S is weight % sulfur content of coal as fired. Emission factor would be calculated by multiplying the weight percent sulfur in the coal by the numerical value preceding S. For example, if fuel is 1.2% sulfur, then S = 1.2. On average for bituminous coal, 95% of fuel sulfur is emitted as SO_2, and only about 0.7% of fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally
small percent of fuel sulfur is emitted as particulate sulfate (References 22-23). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal, about 10% more fuel sulfur is retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

27. Prior to the contractual arrangements for the purchase of sub-bituminous coal for the 2004 test burn, had PEF, or Progress Fuels Corporation, or any other agent for PEF ever contracted to purchase sub-bituminous coal to be burned at Crystal River Units 4 and 5? If you answer in the affirmative, please provide the date(s) of such purchases, the quantities involved, and the vendor. Also, describe the quantities that were delivered, and explain any modifications, terminations, or other depositions of the contractual arrangements or of the subject coal.

Answer:

To the best of our knowledge, there were no contractual arrangements for the purchase of sub-bituminous coal prior to the coal purchased for the 2004 test burn. However, archived records are still being searched.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared PATRICIA Q. WEST, who

(✓) is personally known to me, or

( ) produced ______________________ as identification and who,

being duly sworn, deposes and says that the foregoing answers to Interrogatory No. 25 and 26 of OPC's Fourth Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 060001-EI are true and correct to the best of her knowledge, information and belief.

Patricia Q. West
____
Patricia Q. West

Manager
Title

June C. Mooney
____
Notary Public
State of Florida

My commission Expires: Sept. 18, 2008

JUNE C. MOONEY
MY COMMISSION # DD 335339
EXPIRES: September 18, 2008
Bonded Thru Notary Public Underwriters