EAST KENTUCKY POWER COOPERATIVE

RECEIVED

NOV 14 2008

PUBLIC SERVICE COMMISSION

November 14, 2008

HAND DELIVERED

2008-00472

Ms. Stephanie L. Stumbo
Executive Director
Public Service Commission
Post Office Box 615
211 Sower Boulevard
Frankfort, KY 40602

Dear Ms. Stumbo:

Please find enclosed for filing with the Commission, an original and ten copies of the Application of East Kentucky Power Cooperative, Inc. ("EKPC"), for a Certificate of Public Convenience and Necessity for an Air Quality Control System at the J.S. Cooper Generating Station.

Very truly yours,

Charles A. Lile

Charles A. Lile
Corporate Counsel

Enclosures

Cc: Dennis G. Howard II, Esq.

4775 Lexington Road 40391
P.O. Box 707, Winchester,
Kentucky 40392-0707

Tel. (859) 744-4812
Fax: (859) 744-6008
http://www.ekpc.coop

COMMONWEALTH OF KENTUCKY

RECEIVED
NOV 14 2008
PUBLIC SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	**CASE NO. 2008-** 00472

APPLICATION

1. Applicant, East Kentucky Power Cooperative, Inc., hereinafter referred to as "EKPC", Post Office Box 707, 4775 Lexington Road, Winchester, Kentucky 40392-0707, files this Application for a Certificate of Public Convenience and Necessity for the purchase and installation of an Air Quality Control System ("AQCS") at its J. S. Cooper Generating Station near Burnside, Kentucky ("Cooper Station")

2. This Application is made pursuant to KRS §278.020 and related statutes, and 807 KAR 5:001 Sections 8, 9, and related sections.

3. A copy of Applicant's restated Articles of Incorporation and all amendments thereto were filed with the Public Service Commission (the "Commission") in PSC Case No. 90-197, the Application of EKPC for a Certificate of Public Convenience and Necessity to Construct Certain Steam Service Facilities in Mason County, Kentucky.

4. A copy of the resolution from Applicant's Board of Directors approving the filing of this Application is filed herewith as Application Exhibit 1.

5. Pursuant to KRS §278.020 and 807 KAR 5:001, Section 9, Applicant states that the power requirements of EKPC and its sixteen (16) member distribution cooperatives require the construction of the proposed AQCS facilities, which are more fully described in the various

exhibits filed with this Application. In further support of Applicant's contention that the public convenience and necessity requires the proposed facilities, Applicant submits the following:

(a) The need for the proposed AQCS facilities, is documented in the Consent Decree between EKPC and the Environmental Protection Agency, entered in the United States District Court, Eastern District of Kentucky, Central Division, Lexington, dated September 24, 2007, attached as Application Exhibit 2; and the compliance alternatives considered are documented in the EKPC Cooper/Dale Study Report, attached as Application Exhibit 3.

(b) A description of the proposed AQCS facilities and the technology alternatives considered are documented in the Project Scoping Report, developed for EKPC by Burns & McDonnell Engineering Company, dated November 2008, and included as Application Exhibit 4. A description of the proposed location of the new construction, the manner in which the facilities will be constructed and the identification of any public utilities, corporations, or persons with whom the proposed facilities might compete is included in the Direct Testimony of John R. Twitchell, EKPC Senior Vice-President- G&T Operations, attached as Application Exhibit 10.

(c) Maps showing the proposed location of the site for the AQCS facilities at Cooper Station are attached as Application Exhibits 5a, 5b, and 5c. There are no similar competing facilities owned by others located within the areas of these maps.

(d) A Project Cost Estimate for the proposed AQCS facilities is included on page 5-6 of Application Exhibit 4.

(e) A schedule of the estimated costs of operation of the AQCS facilities after completion is attached as Application Exhibit 6.

(f) The manner of financing proposed for the project, which will include the issuance of indebtedness to the United States of America through the Rural Utilities Service ("RUS"), is discussed in the Direct Testimony of David G. Eames, which is included as Application Exhibit

8. Since U.S. Government financing is anticipated, which does not require Commission approval under KRS §278.300(10), no request for financing approval is made herein.

(g) Applicant's plans for obtaining permits required for the proposed facilities are as follows: EKPC will submit to the Kentucky Natural Resources and Environmental Protection Cabinet ("KNREPC") Division for Air Quality requests to modify existing operating permits to reflect the installation of the proposed scrubber technologies at Cooper Station. EKPC will also request modifications from the KNREPC Division of Water for wastewater discharges associated with this project. EKPC's plans in regard to these permits are discussed further in the Direct Testimony of John R. Twitchell, attached as Application Exhibit 10.

6. Included in this Application are the following Direct Testimonies on Behalf of EKPC:

(a) The Direct Testimony of Robert M. Marshall, EKPC President and Chief Executive Officer, concerning the regulatory requirements surrounding the need for the proposed AQCS facilities, is attached as Application Exhibit 7.

(b) The Direct Testimony of David G. Eames, EKPC Chief Financial Officer, concerning EKPC's plans for financing the proposed facilities, is attached as Application Exhibit 8.

(c) The Direct Testimony of Julia J. Tucker, EKPC Director of Power Supply Planning, concerning the need and justification for the proposed AQCS facilities, is attached as Application Exhibit 9.

(d) The Direct Testimony of John R. Twitchell, concerning the selection of the technology involved, the equipment and facilities proposed to be constructed, the capital and operating costs of the proposed facilities, the proposed construction schedule, and the impact of the AQCS on the fuel requirements for the plant, is attached as Application Exhibit 10.

WHEREFORE, the Applicant, East Kentucky Power Cooperative, Inc., requests that this Commission issue an order granting a Certificate of Public Convenience and Necessity for the construction of the Proposed Facilities.

Respectfully submitted,

DAVID A. SMART

CHARLES A. LILE

ATTORNEYS FOR APPLICANT
EAST KENTUCKY POWER
COOPERATIVE, INC.
P.O. BOX 707
WINCHESTER, KY 40392-0707
(859) 744-4812

**FROM THE MINUTE BOOK OF PROCEEDINGS
OF THE BOARD OF DIRECTORS OF
EAST KENTUCKY POWER COOPERATIVE, INC.**

At a regular meeting of the Board of Directors of East Kentucky Power Cooperative, Inc. held at the Headquarters Building, 4775 Lexington Road, located in Winchester, Kentucky, on Tuesday, July 8, 2008, at 10:30 a. m., EDT, the following business was transacted:

Cooper Station Retrofit Air Pollution Project

After review of the applicable information, a motion was made by Mike Adams and, there being no further discussion, passed to approve the following:

Whereas, East Kentucky Power Cooperative, Inc. ("EKPC") entered into a Consent Decree with the EPA on September 24, 2007 that requires EKPC to either install and continuously operate NO_x and SO_2 emission controls at Cooper Unit 2, or retire and permanently cease operation of Dale Units 3 and 4, by December 31, 2012;

Whereas, EKPC and Burns & McDonnell personnel have studied all options and concluded that retiring Dale Units 3 and 4 presents significant operational and financial risks to the EKPC system;

Whereas, the Kentucky Division of Air Quality ("KDAQ") has submitted its Regional Haze Report to EPA, which indicates that EKPC will need to install a FGD system at Cooper Station to meet Final Rule, 40 CFR Part 51 ("BART") and once the report is approved by EPA, EKPC would then have five years to comply with the BART requirements;

Whereas, The BART requirements make the installation of FGD systems on Cooper Station Units 1 and 2 the only feasible alternative for compliance with the term of the Consent Decree;

Whereas, EKPC will need to seek outside engineering expertise to evaluate and design the specific configuration of the retrofit equipment to best meet its long term needs; and

Whereas, EKPC will need to expeditiously seek regulatory and financing approvals for the project to meet the 2012 deadline; now, therefore, be it

Resolved, That the EKPC Board approves the implementation of a Cooper Station Retrofit Air Pollution Project, and authorizes the President and Chief Executive Officer or his designee, to file for a Certificate of Public Convenience and Necessity with the Kentucky Public Service Commission, to file for required permits and applications with the State of Kentucky and appropriate United States Federal Government agencies, to approve an Engineering Services Agreement with a qualified Engineering firm to scope and design the retrofit air pollution project at Cooper, to authorize a loan application with RUS, and to incorporate the Cooper Station retrofit air pollution project into the 3-Year Construction Work Plan.

The foregoing is a true and exact copy of a resolution passed at a meeting called pursuant to proper notice at which a quorum was present and which now appears in the Minute Book of Proceedings of the Board of Directors of the Cooperative, and said resolution has not been rescinded or modified.

Witness my hand and seal this 8th day of July 2008.

A. L. Rosenberger, Secretary

Corporate Seal

A. L. Rosenberger

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF KENTUCKY
CENTRAL DIVISION at LEXINGTON

CIVIL ACTION NO. 04-34 - KSF

UNITED STATES OF AMERICA PLAINTIFF,

V.

EAST KENTUCKY POWER COOPERATIVE, INC. DEFENDANT.

* * * * * * * * * * *

ORDER

Upon motion of Plaintiff, the United States of America, **IT IS HEREBY ORDERED** that the United States' motion [DE 178] is granted, and that the Consent Decree lodged by the United States on July 2, 2007 [DE 175] is **ENTERED**.

This 24th day of September, 2007.

Signed By:
Karl S. Forester KSF
United States Senior Judge

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF KENTUCKY
CENTRAL DIVISION
LEXINGTON

UNITED STATES OF AMERICA Plaintiff, v. EAST KENTUCKY POWER COOPERATIVE, INC., Defendant.	)	Civil Action No. 04-34-KSF

CONSENT DECREE

TABLE OF CONTENTS

WHEREAS, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA"), filed a Complaint against East Kentucky Power Cooperative, Inc. ("EKPC") pursuant to Sections 113(b) and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413(b) and 7477, for injunctive relief and civil penalties for alleged violations of:

(a) the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92;

(b) the New Source Performance Standards ("NSPS") 42 U.S.C. § 7411;

(c) Title V of the Act, 42 U.S.C. § 7661 *et seq.*;

(d) the federally-enforceable State Implementation Plan ("SIP") developed by the Commonwealth of Kentucky; and

WHEREAS, in its Complaint, Plaintiff alleges, *inter alia,* that EKPC failed to obtain the necessary permits and install the controls necessary under the Act to reduce its sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that EKPC violated various operating permit conditions;

WHEREAS, the Complaint alleges claims upon which relief can be granted against EKPC under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, EKPC, a rural electric cooperative based in Winchester, Kentucky, has answered the Complaint filed by the United States;

WHEREAS EKPC has denied and continues to deny the violations alleged in the NOVs and the Complaint; maintains that it has been and remains in compliance with the Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Decree solely to avoid the costs and uncertainties of litigation and to improve the environment;

WHEREAS, EPA provided EKPC and the Commonwealth of Kentucky with actual notices of violations pertaining to EKPC's alleged violations, in accordance with Section 113(a)(1) and (b) of the Act, 42 U.S.C. § 7413(a)(1) and (b);

WHEREAS, the Parties anticipate that the installation and operation of pollution control equipment pursuant to this Consent Decree will achieve significant reductions in SO_2, NO_x and PM emissions and thereby improve air quality;

WHEREAS, the United States and EKPC have agreed, and the Court by entering this Consent Decree finds: that this Consent Decree has been negotiated in good faith and at arms length; that this settlement is fair, reasonable, consistent with the goals of the Act, in the best interest of the Parties and in the public interest; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

and

WHEREAS, the United States and EKPC have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint, notices of violations and otherwise; it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, and 1355, and Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act,

42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, EKPC waives all objections and defenses that it may have to the Court's jurisdiction over this action, to the Court's jurisdiction over EKPC, and to venue in this District. EKPC shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. For purposes of the Complaint filed by the United States in this matter and resolved by the Consent Decree, and for purposes of entry and enforcement of this Consent Decree, EKPC waives any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and EKPC. Except as provided in Section XXVI (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. Upon entry, the provisions of this Consent Decree shall apply to and be binding upon the United States and EKPC, its successors and assigns, and EKPC's officers, employees, and agents solely in their capacities as such.

3. EKPC shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, EKPC shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, EKPC shall not assert as a defense the failure of its officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless EKPC establishes that such failure resulted from a Force Majeure Event, as defined in Paragraph 143 of this Consent Decree.

III. DEFINITIONS

4. A "1-Hour Average NO_x Emission Rate" for a gas-fired, electric generating unit shall be expressed as the average concentration in parts per million ("ppm") by dry volume, corrected to 15% O_2, as averaged over one (1) hour. In determining the 1-Hour Average NO_x Emission Rate, EKPC shall use CEMS in accordance with the applicable reference methods specified in 40 C.F.R. Part 60 to calculate emissions for each 15 minute interval within each clock hour, except as provided in this Paragraph. Compliance with the 1-Hour Average NO_x Emission Rate shall be shown by averaging all 15-minute CEMS interval readings within a clock hour, except that any 15-minute CEMS interval that contains any part of a Start-up or Shut Down shall not be included in the calculation of that one-hour average. A minimum of two 15-minute CEMS interval readings within a clock hour, not including Start-up or Shut-Down intervals, is required to determine compliance with the 1-Hour Average NO_x Emission Rate. All emissions recorded by CEMS shall be reported in one hour averages.

5. A "30-Day Rolling Average Emission Rate" for a Unit or "Combined 30-Day Rolling Average Emission Rate" for the Spurlock Plant shall be expressed as lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the Unit (in the case of a 30-Day Rolling Average Emission Rate) or the Spurlock Plant (in the case of a Combined 30-Day Rolling Average Emission Rate) during an Operating Day and the previous twenty-nine (29) Operating Days; second, sum the total heat input to the Unit (in the case of a 30-Day Rolling Average Emission Rate) or the Spurlock Plant (in the case of a Combined 30-Day Rolling Average Emission Rate) in mmBTU during the Operating Day and the previous twenty-nine (29) Operating Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Operating Days by the total heat input during the thirty (30) Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. A new Combined 30-Day Rolling

Average Emission Rate shall be calculated for each new Operating Day during which both Spurlock 1 and Spurlock 2 fire Fossil Fuel. Each 30-Day Rolling Average Emission Rate and Combined 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of start-up, shutdown and Malfunction within an Operating Day, except as follows:

a. For emissions of NO_x from Spurlock 1 only, EKPC shall include all emissions commencing from the time Spurlock 1 is synchronized with a utility electric distribution system through the time that Spurlock 1 ceases to combust fossil fuel and the fire is out in the boiler;

b. Emissions of NO_x that occur during the fifth and subsequent Cold Start Up Period(s) that occur in any 30-day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate and Combined 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emission Rate or Combined 30-Day Rolling Average Emission Rate, and if EKPC has installed, operated and maintained the SCR in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any fossil fuel) for a period of six hours or more. The emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) shall be the less of (1) those NO_x emissions emitted during the eight hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight hours later or (2) those emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature as specified by the catalyst manufacturer;

c. For Cold Start Up Periods that occur at Spurlock 1 prior to April 1, 2008, emissions of NO_x that occur during the first and second Cold Start Up Period(s) that occur in any 30-day period shall also be excluded from the calculation of the 30-Day Rolling Average Emission Rate and Combined 30-Day Rolling Average Emission Rate under the same terms and conditions as provided in Subparagraph b; and

d. Emissions that occur during a period of Malfunction shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate and Combined 30-Day Rolling Average Emission Rate if EKPC provides notice of the Malfunction to EPA and takes all reasonable measures to minimize the duration of such Malfunction and prevent the recurrence of such Malfunctions in the future, in accordance with Paragraph 152 (Malfunction Events) of this Consent Decree.

6. "30-Day Rolling Average SO_2 Removal Efficiency" means the percent reduction in the mass of SO_2 achieved by a Unit's pollution control device over a 30-Operating Day period. This percent reduction shall be calculated by subtracting the outlet 30-Day Rolling Average Emission Rate from the inlet 30-Day Rolling Average Emission Rate, dividing that difference by the inlet 30-Day Rolling Average Emission Rate, and then multiplying by 100. In the event the 30-Day Rolling Average SO_2 Removal Efficiency does not meet the requirements of this consent decree, a 30-Day Rolling Average SO_2 emission rate of 0.100 lb/mmBTU or less shall satisfy the removal efficiency requirement. A new 30-Day Rolling Average SO_2 Removal Efficiency shall be calculated for each new Operating Day. EKPC may exclude Malfunctions from the calculation of a 30-Day Rolling Average SO_2 Removal Efficiency only to the extent that such Malfunctions have been excluded from the underlying 30-Day Rolling Average Emission Rates.

7. "Boiler Island" means a Unit's (A) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (B) combustion air system; (C) steam generating system (firebox, boiler tubes, and walls); and (D) draft system (excluding the stack), all as further described in "Interpretation of Reconstruction," by John B. Rasnic, U.S. EPA (November 25, 1986) and attachments thereto.

8. "Capital Expenditure" means all capital expenditures, as defined by Generally Accepted Accounting Principles ("GAAP"), excluding the cost of installing or upgrading pollution control devices.

9. "CEMS" or "Continuous Emission Monitoring System" means, for obligations involving NO_x and SO_2 under this Consent Decree, the devices defined in 40 C.F.R. § 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

10. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§7401-7671q, and its implementing regulations.

11. "Consent Decree" or "Decree" means this Consent Decree and the Appendix hereto, which is incorporated into this Consent Decree.

12. "Cooper Plant" means the John Sherman Cooper Power Station located near Somerset, Kentucky, consisting of the following coal-fired Units: Unit 1 (124 MW) ("Cooper 1") and Unit 2 (240 MW) ("Cooper 2").

13. "Dale Plant" means Unit 3 (80 MW) ("Dale 3") and Unit 4 (80 MW) ("Dale 4") (and shall exclude Units 1 and 2) of the William C. Dale Power Station, located near Winchester, Kentucky.

14. "EKPC System" means, collectively, the Spurlock Plant, Cooper Plant, and Dale Plant.

15. "EKPC System Unit" means a unit included in the EKPC System.

16. "Emission Rate" means the number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU") or the average concentration of pollutant in parts per million by dry volume ("ppm") corrected to 15% O_2, measured in accordance with this Consent Decree.

17. "EPA" means the United States Environmental Protection Agency.

18. "Flue Gas Desulfurization System," or "FGD," means a pollution control device that employs flue gas desulfurization technology for the reduction of sulfur dioxide.

19. "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas.

20. "Improved Unit" means, in the case of NO_x, an EKPC System Unit scheduled to begin year-round operation of SCR technology pursuant to Paragraph 52, or, following EKPC's election pursuant to Paragraph 50, scheduled to be retired or equipped with SCR (or equivalent NO_x control technology approved pursuant to Paragraph 54). In the case of SO_2, "Improved Unit" means an EKPC System Unit scheduled to be equipped with an FGD pursuant to Paragraph 64 (or equivalent SO_2 control technology approved pursuant to Paragraph 66) or, following EKPC's election pursuant to Paragraph 50, scheduled to be retired or equipped with FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 66). Following EKPC's election pursuant to Paragraph 50, either, but not both, of (1) Cooper Unit 2, or (2) Dale Units 3 and 4, may be considered "Improved Units." Neither (1) Cooper Unit 2 nor (2) Dale

Units 3 and 4 shall be considered an "Improved Unit" unless and until an election is made pursuant to Paragraph 50.

21. "lb/mmBTU" means one pound of a pollutant per million British thermal units of heat input.

22. "Malfunction" means malfunction as that term is defined under 40 C.F.R.§ 60.2.

23. "MCR" means maximum continuous rating.

24. "MW" means a megawatt or one million Watts.

25. "National Ambient Air Quality Standards" or "NAAQS" means national ambient air quality standards that are promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

26. "New Units" means the following coal-fired circulating fluidized bed ("CFB") Units that commenced operation after the filing of the Complaint in this action and/or commence operation after entry of this Consent Decree and are owned all or in part by EKPC: Spurlock Unit 3 (305 MW), Spurlock Unit 4 (315 MW), Smith Unit 1 (315 MW) and Smith Unit 2 (315 MW).

27. "NO_x" means oxides of nitrogen, measured in accordance with the provisions of this Consent Decree.

28. "Nonattainment NSR" means the nonattainment area New Source Review program under Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515, 40 C.F.R. Part 51.

29. "NSPS" means New Source Performance Standards within the meaning of Part A of Subchapter I, of the Clean Air Act, 42 U.S.C. § 7411, 40 C.F.R. Part 60.

30. "Operating Day" means any calendar day on which a Unit fires Fossil Fuel.

31. "Other Unit" means any EKPC System Unit that is not an Improved Unit for the pollutant in question.

32. "Ownership Interest" means all or part of EKPC's legal or equitable interest in any EKPC System Unit.

33. "Parties" means EKPC and the United States of America, and "Party" means either one of the two named "Parties."

34. "Permitting State" means the Commonwealth of Kentucky.

35. "Plaintiff" means the United States of America.

36. "Pollution Control Upgrade Analysis" means the technical study, analysis, review, and selection of control technology recommendations (including an emission rate or removal efficiency) identical to that which would be performed in connection with an application for a federal PSD permit, taking into account the characteristics of the existing facility. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in accordance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT), as that term is defined in 40 C.F.R. §52.21(b)(12), including, without limitation, the December 1, 1987 EPA Memorandum from J. Craig Potter, Assistant Administrator for Air and Radiation, regarding Improving New Source Review (NSR) Implementation. Nothing in this Decree shall be construed either to: (A) alter the force and effect of statements known as or characterized as "guidance" or (B) permit the process or result

of a “Pollution Control Upgrade Analysis” to be considered BACT for any purpose under the Act.

37. “PM” means particulate matter, measured in accordance with the provisions of this Consent Decree.

38. “PM CEMS,” “Mercury CEMS,” “PM Continuous Emission Monitoring System,” or “Mercury Continuous Emission Monitoring System” means, as specified in Section VII.C (PM and Mercury Monitoring) of this Consent Decree, the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic or paper record of PM or Mercury emissions.

39. “PM Control Device” means an electrostatic precipitator (“ESP”) or a baghouse (“BH”) or any other device which reduces emissions of particulate matter (PM).

40. “PM Emission Rate” means the number of pounds of PM emitted per million BTU of heat input (lb/mmBTU), as measured in annual (or biennial) stack tests in accordance with the reference method set forth in 40 C.F.R. Part 60, App. A, Method 5 (filterable portion only).

41. “PSD” means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492 and 40 C.F.R. Part 52.

42. “Re-power” shall mean either (1) the replacement of an existing pulverized coal boiler through the construction of a new circulating fluidized bed ("CFB") boiler or other clean coal technology of equivalent environmental performance that at a minimum achieves and maintains a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU for SO_2 or a 30-Day Rolling Average SO_2 Removal Efficiency of at least ninety-five percent (95%); a 30-

Day Rolling Average Emission Rate not greater than 0.070 lb/mmBTU for NO_x, and a PM Emission Rate not greater than 0.015 lb/mmBTU; or (2) the modification of a Unit, or removal and replacement of Unit components, such that the modified or replaced Unit generates electricity through the use of new combined cycle combustion turbine technology fueled by natural gas containing no more than 0.5 grains of sulfur per 100 standard cubic feet of natural gas, and at a minimum achieves and maintains a 1-Hour Average NO_x Emission Rate not greater than 2.0 ppm.

43. "Selective Catalytic Reduction System" or "SCR" means a pollution control device that employs selective catalytic reduction technology for the reduction of NO_x emissions.

44. "SO_2" means sulfur dioxide, measured in accordance with the provisions of this Consent Decree.

45. "SO_2 Allowance" means "allowance" as defined at 42 U.S.C. § 7651a(3): "an authorization, allocated to an affected unit by the Administrator [of EPA] under [Subchapter IV of the Act], to emit, during or after a specified calendar year, one ton of sulfur dioxide."

46. "Spurlock Plant" means the Spurlock Power Station located near Maysville, Kentucky, consisting of the following coal-fired cogeneration Units: Unit 1 (344 MW) ("Spurlock 1") and Unit 2 (555 MW) ("Spurlock 2"). Spurlock 1 and 2 are each configured to supply thermal energy to an adjacent box manufacturing plant.

47. "System-Wide 12-Month Rolling Tonnage" means the sum of the tons of the pollutant in question emitted from the EKPC System in the most recent complete month and the previous eleven (11) months. A new System-Wide 12-Month Rolling Tonnage shall be calculated for each new complete month in accordance with the provisions of this Consent

Decree. The calculation of each System-Wide 12-Month Rolling Tonnage shall include the pollutants emitted during periods of startup, shutdown, and Malfunction within each calendar month, except as otherwise provided by the Force Majeure provisions of this Consent Decree.

48. "Title V Permit" means the permit required of EKPC's major sources under Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e.

49. "Unit" means, solely for the purposes of this Consent Decree, collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for the production of electricity.

IV. ELECTION TO EITHER INSTALL EMISSION CONTROLS AT COOPER 2 OR RETIRE OR RE-POWER DALE 3 AND 4

50. No later than December 31, 2009, EKPC shall elect in writing to Plaintiff to either (1) install and continuously operate NO_x emission controls at Cooper 2 by December 31, 2012, and SO_2 emissions controls by June 30, 2012, as required in Paragraphs 53 and 65, or (2) retire and permanently cease to operate Dale 3 and 4 by December 31, 2012. Should EKPC retire and cease to operate Dale 3 and 4 pursuant to Option (2), EKPC may resume operation of such Units only if EKPC first Re-powers the Units pursuant to Paragraph 42 of this Decree, commences commercial operation of such Re-powered Units by May 31, 2014, and thereafter continues to operate in compliance with the rates set forth in Paragraph 42. Should EKPC choose to Re-power Dale Units 3 and 4, EKPC shall timely apply for a preconstruction permit from the Permitting State under 401 Ky. Admin. Reg. 51:017 prior to commencing such Re-powering. In applying for such permit EKPC shall seek, as part of the permit, provisions requiring Emission Rates no greater than those set forth in Paragraph 42.

V. NO_x EMISSION REDUCTIONS AND CONTROLS

A. NO_x Emission Controls

51. Beginning 60 days after entry of this Consent decree, and continuing until December 31, 2012, EKPC shall operate year-round the SCR technology on Spurlock 1 and Spurlock 2 to achieve and maintain the Emission Rates required by this Paragraph. EKPC shall operate year-round the SCR technology on Spurlock 1 so as to achieve and maintain a 30-Day Rolling Average Emission Rate for NO_x not greater than 0.120 lb/mmBTU. EKPC shall operate year-round the SCR technology on Spurlock 2 so as to achieve and maintain a 30-Day Rolling Average Emission Rate for NO_x not greater than 0.100 lb/mmBTU. During periods when both Spurlock 1 and Spurlock 2 are operating, EKPC shall operate the SCR technology on both Spurlock 1 and 2 so as to achieve and maintain a Combined 30-Day Rolling Average Emission Rate for those two Units for NO_x not greater than 0.100 lb/mmBTU.

52. Beginning on January 1, 2013, and continuing thereafter, EKPC shall operate year-round the SCR technology on Spurlock 1 and 2 so as to achieve and maintain a NO_x 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU for each Unit.

53. Pursuant to Paragraph 50, if EKPC elects to install and continuously operate emission controls at Cooper 2, then beginning on December 31, 2012, EKPC shall install and commence continuous operation of year-round SCR technology on Cooper 2 (or equivalent NO_x control technology approved pursuant to Paragraph 54) so as to achieve, and thereafter maintain, a NO_x 30-Day Rolling Average Emission Rate not greater than 0.080 lb/mmBTU.

54. With prior written notice to and written approval from EPA, EKPC may, in lieu of installing and operating an SCR at Cooper 2, install and operate equivalent NO_x control technology so long as such equivalent NO_x control technology is designed for at least a 90%

removal efficiency for NO_x and achieves and thereafter maintains a 30-Day Rolling Average Emission Rate no less stringent than 0.080 lb/mmBTU NO_x.

55. In accordance with the dates prescribed in Paragraphs 51, 52, and 53, EKPC shall continuously operate each SCR (or equivalent NO_x control technology approved pursuant to Paragraph 54) at all times that the Unit it serves is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the SCR or equivalent technology, for minimizing emissions to the extent practicable.

56. Beginning 30 days from entry of this Consent Decree, EKPC shall also operate low NO_x burners ("LNB") on all of the units within the EKPC System and over-fire air on Spurlock Unit 2 at all times that the units are in operation.

B. System-Wide NO_x Emission Limits

57. EKPC shall comply with the following System-Wide 12-Month Rolling Tonnage limitations for NO_x, which apply to all EKPC System Units collectively:

For the 12-Month Period Commencing on the Date Specified Below, and Each 12-Month Period Thereafter:	System-wide 12-Month Rolling Tonnage Limitation for NO_x
January 1, 2008	11,500 tons
January 1, 2013	8,500 tons
January 1, 2015	8,000 tons

58. The system-wide annual emissions limits for NO_x set forth in Paragraph 57 shall apply prospectively from the specified date on which a 12-month period commences, that is compliance with the cap shall first be determined 12 months following the commencement date

specified above, and shall end on the date that the subsequent system-wide limit, if any, takes effect. EKPC may not use NO_x Allowances to comply with these system-wide limitations.

C. Use of NO_x Allowances

59. Except as provided in this Consent Decree, EKPC shall not sell or trade any NO_x Allowances allocated to the EKPC System that would otherwise be available for sale or trade as a result of the actions taken by EKPC to comply with the requirements of this Consent Decree.

60. Except as provided in this Consent Decree, NO_x Allowances allocated to the EKPC System may be used by EKPC only to meet its own federal and/or State Clean Air Act regulatory requirements for any EKPC System Unit or New Unit.

61. Provided that EKPC is in compliance with the system-wide NO_x emission limitations of this Consent Decree, nothing in this Consent Decree shall preclude EKPC from selling or transferring NO_x Allowances allocated to the EKPC System that become available for sale or trade as a result of:

a. activities that reduce NO_x emissions at any EKPC System Unit prior to the date of entry of this Consent Decree;

b. the installation and operation of any NO_x pollution control technology or technique that is not otherwise required under this Consent Decree;

c. achievement and maintenance of NO_x emission rates below both (1) a NO_x 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU (for Spurlock 1 and 2) or 0.080 lb/mmBTU (for Cooper 2) and (2) the NO_x Combined 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU established by this Consent Decree; provided, however, that any achievement and maintenance of NO_x emission rates resulting from the use of Subparagraph 5.c shall not be sold, traded or used by EKPC;

d. permanent shutdown or repowering of any EKPC System Unit not otherwise required by this Consent Decree;

e. a fuel change at a Unit that results in an emission reduction, provided that the emission reduction is made enforceable through modification of this Consent Decree; or

f. other emission reduction measures that are agreed to by the Parties and made enforceable through modification of this Consent Decree,

so long as EKPC timely reports the generation of such surplus NO_x Allowances in accordance with Section XII (Periodic Reporting) of this Consent Decree. EKPC shall be allowed to sell or transfer NO_x Allowances equal to the NO_x emissions reductions achieved for any given year by any of the actions specified in Subparagraphs 61.b. through 61.f. only to the extent that the total NO_x emissions from all EKPC System Units are below the System-Wide 12-Month Rolling Tonnage limitation for that year.

62. EKPC may not purchase or otherwise obtain NO_x Allowances from another source for purposes of complying with the requirements of this Consent Decree. However, nothing in this Consent Decree shall prevent EKPC from purchasing or otherwise obtaining NO_x Allowances from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law.

D. General NO_x Provisions

63. In determining Emission Rates for NO_x, EKPC shall use CEMS in accordance with the procedures specified in 40 C.F.R. Part 75.

VI. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. SO_2 Emission Controls

1. New FGD Installations

64. EKPC shall install and commence continuous operation of an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 66) on the following Units within the EKPC System so as to achieve, by the dates specified below, and thereafter maintain, a 30-Day Rolling Average Removal Efficiency for SO_2 of at least ninety-five percent (95%) or a 30-Day Rolling Average SO_2 Emission Rate of no greater than 0.100 lb/mmBTU:

Unit	Date by which EKPC must install and commence continuous operation of an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 66)	Date by which EKPC's FGD Must Achieve and Maintain 30-Day Rolling Average Removal Efficiency or Emission Rate for SO_2
Spurlock 2	October 1, 2008	January 1, 2009
Spurlock 1	June 30, 2011	June 30, 2011

65. Pursuant to Paragraph 50, if EKPC elects to install and continuously operate emission controls at Cooper 2, then beginning on June 30, 2012, EKPC shall install and commence continuous operation of FGD technology (or equivalent SO_2 control technology approved pursuant to Paragraph 66) on Cooper 2 so as to achieve, and thereafter maintain, a 30-day Rolling Average SO_2 Removal Efficiency of at least ninety-five percent (95%) for Cooper 2 or a 30-Day Rolling Average SO_2 Emission Rate of no greater than 0.100 lb/mmBTU.

66. With prior written notice to and written approval from EPA, EKPC may, in lieu of installing and operating an FGD at any Unit specified in Paragraph 64 and 65, install and operate equivalent SO_2 control technology so long as such equivalent SO_2 control technology achieves and maintains a 30-Day Rolling Average SO_2 Removal Efficiency of at least ninety-

five percent (95%) or a 30-Day Rolling Average SO_2 Emission Rate of no greater than 0.100 lb/mmBTU.

2. Continuous Operation of SO_2 Controls

67. EKPC shall continuously operate each FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 66) covered under this Consent Decree at all times that the Unit it serves is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the FGD or equivalent technology, for minimizing emissions to the extent practicable.

B. System-Wide SO_2 Emission Limits

68. EKPC shall comply with the following System-Wide 12-Month Rolling Tonnage limitations for SO_2, which apply to all EKPC System Units collectively:

For the 12-Month Period Commencing on the Date Specified Below, and Each 12-Month Period Thereafter:	**System-Wide 12-Month Rolling Tonnage Limitation for SO_2**
October 1, 2008	57,000 tons
July 1, 2011	40,000 tons
January 1, 2013	28,000 tons

69. Each of the system-wide annual emission limits for SO_2 set forth in Paragraph 68 shall apply prospectively from the specified date on which a 12-month period commences, that is compliance with the cap shall first be determined 12 months following the commencement date specified above, and shall end on the date that the subsequent system-wide limit, if any, takes effect. EKPC shall not use SO_2 allowances or credits to comply with these system-wide limitations.

C. Surrender of SO_2 Allowances

70. For purposes of this Subsection, the "surrender of allowances" means permanently surrendering allowances from the accounts administered by EPA for all units in the EKPC System, so that such allowances can never be used to meet any compliance requirement under the Clean Air Act, the Kentucky SIP, or this Consent Decree.

71. EKPC may use any SO_2 Allowances allocated by EPA to the EKPC System only to meet its own federal and/or State Clean Air Act regulatory requirements for any EKPC System Unit or New Unit. EKPC shall not sell or transfer any allocated EKPC System SO_2 Allowances to a third party, except as provided in Paragraphs 72, 73, and 76 below.

72. For each calendar year beginning with calendar year 2008, EKPC shall surrender to EPA, or transfer to a non-profit third party selected by EKPC for surrender, SO_2 Allowances allocated to EKPC System Units that are surplus to its Clean Air Act SO_2 Allowance-holding requirements for the EKPC System Units and New Units, collectively, for that year. EKPC shall make such surrender annually, within forty-five (45) days of EKPC's receipt from EPA of the Annual Deduction Reports for SO_2. Any surrender need not include the specific SO_2 Allowances that were allocated to EKPC System Units, so long as EKPC surrenders SO_2 Allowances that are from the same year or an earlier year and that are equal to the number required to be surrendered under this Paragraph 72.

73. If any allowances are transferred directly to a non-profit third party, EKPC shall include a description of such transfer in the next report submitted to EPA pursuant to Section XII (Periodic Reporting) of this Consent Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the SO_2 Allowances and a listing of the serial numbers of the transferred SO_2 Allowances; and (ii) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and

will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO_2 Allowances, EKPC shall include a statement that the third-party recipient(s) surrendered the SO_2 Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 74 within one (1) year after EKPC transferred the SO_2 Allowances to them. EKPC shall not have complied with the SO_2 Allowance surrender requirements of this Paragraph 73 until all third-party recipient(s) shall have actually surrendered the transferred SO_2 Allowances to EPA.

74. For all SO_2 Allowances surrendered to EPA, EKPC or the third-party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, EKPC or the third-party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO_2 Allowances being surrendered.

75. The requirements in Paragraphs 71, 72, 73, 74, and 76 of this Decree pertaining to EKPC's use and retirement of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree. These provisions shall survive any termination of this Decree in whole or in part.

76. Provided that EKPC is in compliance with the system-wide SO_2 emissions limitations of this Consent Decree, nothing in this Consent Decree shall preclude EKPC from banking, selling or transferring SO_2 Allowances allocated to the EKPC System that become available for sale or trade as a result of:

a. activities that reduce SO_2 emissions at any EKPC System Unit prior to the date of entry of this Consent Decree;

b. the installation and operation of any SO_2 pollution control technology or technique that is not otherwise required under this Consent Decree;

c. achievement and maintenance of a 30-Day Rolling Average SO_2 Removal Efficiency at an Improved Unit that is below the applicable 30-Day Rolling Average SO_2 Removal Efficiency limit specified in Paragraphs 64 and 65;

d. permanent shutdown or repowering of any EKPC System Unit not otherwise required by the Consent Decree;

e. a fuel change at a Unit that results in an emission reduction, provided that the emission reduction is made enforceable through modification of this Consent Decree; or

f. other emission reduction measures that are agreed to by the Parties and made enforceable through modification of this Consent Decree,

so long as EKPC timely reports the generation of such surplus SO_2 Allowances in accordance with Section XII (Periodic Reporting) of this Consent Decree. EKPC shall be allowed to bank, sell or transfer SO_2 Allowances equal to the SO_2 emissions reductions achieved for any given year by any of the actions specified in Subparagraphs 76.b. through 76.f. only to the extent that the total SO_2 emissions from all EKPC System Units are below the System-Wide 12-Month Rolling Tonnage limitation for that year.

77. Nothing in this Consent Decree shall prevent EKPC from purchasing or otherwise obtaining SO_2 Allowances from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law.

D. Fuel Limitations

78. EKPC shall not burn coal having a sulfur content greater than any amount authorized by regulation or State permit at any EKPC System Unit.

E. General SO_2 Provisions

79. In determining Emission Rates for SO_2, EKPC shall use CEMS in accordance with the procedures specified in 40 C.F.R. Part 75.

80. For Units that are required to be equipped with SO_2 control equipment and that are subject to the percent removal efficiency requirements of this Consent Decree, the outlet SO_2 Emission Rate and the inlet SO_2 Emission Rate shall be determined based on the data generated in accordance with 40 C.F.R. Part 75.15 (1999) (using SO_2 CEMS data from both the inlet and outlet of the control device).

VII. PM AND MERCURY EMISSION REDUCTIONS AND CONTROLS

A. Optimization of PM Emission Controls

81. Within ninety (90) days after entry of this Consent Decree and continuing thereafter, EKPC shall continuously operate each PM control device on its EKPC System Units to maximize PM emission reductions, consistent with manufacturers' specifications, the operational design and maintenance limitations of the Units and good engineering practices. Specifically, EKPC shall, at a minimum: (a) energize each section of the ESP for each Unit, regardless of whether that action is needed to comply with opacity limits; (b) maintain the energy or power levels delivered to the ESPs for each Unit to achieve the greatest possible

removal of PM; (c) make best efforts to expeditiously repair and return to service transformer-rectifier sets when they fail; and (d) inspect for, and schedule for repair, any openings in ESP casings and ductwork to minimize air leakage. Within two hundred seventy (270) days after entry of this Consent Decree and continuing thereafter, EKPC shall also optimize the plate-cleaning and discharge-electrode-cleaning systems for the ESPs at each EKPC System Unit by varying the cycle time, cycle frequency, rapper-vibrator intensity, and number of strikes per cleaning event, of these systems to minimize PM emissions.

B. Upgrade of Existing PM Emission Controls

82. Within 365 days of lodging of this Consent Decree, EKPC shall demonstrate that each of the EKPC System Units can achieve and maintain a PM Emission Rate of no greater than 0.030 lb/mmBTU in accordance with Paragraph 87. In the alternative and in lieu of demonstrating compliance with the PM Emission Rate applicable under this Paragraph 82, EKPC may elect to undertake an upgrade of the existing PM emissions control equipment for any such Unit based on a PM Pollution Control Upgrade Analysis for that Unit. The preparation, submission, and implementation of such PM Pollution Control Upgrade Analysis shall be undertaken and completed in accordance with the compliance schedules and procedures specified in Paragraph 84.

83. Demonstration and Compliance with PM Emission Limit. If EKPC demonstrates by the applicable date set forth in Paragraph 82 that a Unit can achieve and maintain a PM Emission Rate of no greater than 0.030 lb/mmBTU, EKPC shall thereafter operate that Unit to maximize PM emission reductions, consistent with the Unit's operational design and safety requirements, and shall achieve and maintain a PM Emission Rate no greater than 0.030 lb/mmBTU.

84. PM Emission Control Upgrade. For each EKPC System Unit for which EKPC does not elect to meet a PM Emission Rate of 0.030 lb/mmBTU, EKPC shall prepare, submit, and implement a PM Pollution Control Upgrade Analysis in accordance with this Paragraph 84. Such PM Pollution Control Upgrade Analysis shall include proposed upgrades to the PM pollution control device and a proposed alternate PM Emission Rate that the Unit shall meet upon completion of such upgrade. For each Unit for which such a PM Pollution Control Upgrade Analysis is required, EKPC shall deliver such PM Pollution Control Upgrade Analysis to EPA for approval pursuant to Section XIII (Review and Approval of Submittals) of this Consent Decree within 180 days of the date on which the particular EKPC System Unit is unable to make the demonstration required by Paragraph 83.

a. In conducting the PM Pollution Control Upgrade Analysis for any Unit, EKPC need not consider any of the following PM control measures:

i. the complete replacement of the existing ESP with a new ESP, FGD, or baghouse, or

ii. the upgrade of the existing ESP controls through the installation of a supplemental PM Control Device, through the refurbishment of existing PM Control Devices, or through other measures, if the costs of such upgrade are equal to or greater than the costs of a replacement ESP, FGD, or baghouse (on a total dollar-per-ton-of-pollutant-removed basis).

With each PM Pollution Control Upgrade Analysis delivered to EPA, EKPC shall simultaneously deliver all documents that support or were considered in preparing such PM Pollution Control Upgrade Analysis. EKPC shall retain a qualified contractor to assist in the performance and completion of each PM Pollution Control Upgrade Analysis.

b. Beginning one (1) year after EPA approval of the recommendation(s) made in a PM Pollution Control Upgrade Analysis for a Unit, EKPC shall not operate that Unit unless all equipment called for in the recommendation(s) of the Pollution Control Upgrade Analysis has been installed. An installation period longer than one year may be allowed if EKPC makes such a request in the PM Pollution Control Upgrade Analysis and EPA determines such additional time is necessary due to factors such as the magnitude of the PM control project or the need to address reliability concerns that could result from multiple EKPC System Unit outages. Upon installation of all equipment recommended under an approved PM Pollution Control Upgrade Analysis, EKPC shall operate such equipment in compliance with the recommendation(s) of the approved PM Pollution Control Upgrade Analysis, including compliance with any PM Emission Rate specified by the recommendation(s).

85. EKPC shall continuously operate each ESP in the EKPC System at all times that the Unit it serves is combusting Fossil Fuel, in compliance with manufacturers' specifications, the operational design and maintenance limitations of the Unit, and good engineering practices.

C. PM and Mercury Monitoring

1. PM Stack Tests

86. Beginning in calendar year 2008, and continuing annually thereafter, EKPC shall conduct a PM performance test on each EKPC System Unit. The annual stack test requirement imposed on each EKPC System Unit by this Paragraph 86 may be satisfied by stack tests conducted by EKPC as required by its permits from the Kentucky Natural Resources and

Environmental Protection Cabinet for any year that such stack tests are required under the permits. EKPC may perform biennial rather than annual testing provided that (a) two of the most recently completed test results from tests conducted in accordance with 40 C.F.R. Part 60, Appendix A-1, Method 5 demonstrate that the PM emissions are equal to or less than 0.015 lb/mmBTU, or (b) the Unit is equipped with a PM CEMS in accordance with Paragraphs 88 through 95. EKPC shall perform annual rather than biennial testing the year immediately following any test result demonstrating that the particulate matter emissions are greater than 0.015 lb/mmBTU, unless the Unit is equipped with a PM CEMS in accordance with Paragraphs 88 through 95.

87. The reference and monitoring methods and procedures for determining compliance with PM Emission Rates shall be those specified in 40 C.F.R. Part 60, Appendix A-1, Method 5. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. § 60.48a (b) and (e), or any federally approved method contained in the Kentucky SIP. EKPC shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f). The results of each PM stack test shall be submitted to EPA within 30 days of completion of each test.

2. PM CEMS

88. EKPC shall install and operate PM CEMS in accordance with Paragraphs 89 through 95. Operation of such PM CEMS shall be in accordance with 40 C.F.R. Part 60, App. B, Performance Specification 11, and App. F Procedure 2. Each PM CEMS shall comprise a continuous particle mass monitor measuring PM concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units of lb/mmBTU. EKPC shall maintain, in an electronic database, the hourly average emission

values of all PM CEMS in lb/mmBTU. EKPC shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating.

89. No later than six (6) months after entry of this Consent Decree, EKPC shall submit to EPA for review and approval pursuant to Section XIII (Review and Approval of Submittals) of this Consent Decree a plan for the installation and certification of each PM CEMS.

90. EKPC shall install, certify, and operate PM CEMS on two (2) Units, stacks or common stacks in accordance with the following schedule:

Stack	**Deadline to Commence Operation of PM CEMS**
Spurlock 2	10/1/08
Cooper 1	12/31/12

91. No later than one hundred twenty (120) days prior to the deadline to commence operation of each PM CEMS, EKPC shall submit to EPA for review and approval pursuant to Section XIII (Review and Approval of Submittals) of this Consent Decree a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. Following EPA's approval of the protocol, EKPC shall thereafter operate each PM CEMS in accordance with the approved protocol.

92. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, EKPC shall use the criteria set forth in 40 C.F.R. Part 60, App. B, Performance Specification 11, and App. F Procedure 2. EKPC shall include in its QA/QC protocol a description of any periods in which it proposes that the PM CEMS may not be in operation in accordance with Performance Specification 11.

93. No later than ninety (90) days after EKPC begins operation of the PM CEMS, EKPC shall conduct tests of each PM CEMS to demonstrate compliance with the PM CEMS installation and certification plan submitted to and approved by EPA in accordance with Paragraph 89.

94. EKPC shall operate the PM CEMS for at least two (2) years on each of the Units specified in Paragraph 90. After two (2) years of operation, EKPC may attempt to demonstrate that it is infeasible to continue operating PM CEMS. As part of that demonstration, EKPC shall submit an alternative PM monitoring plan for review and approval by the United States. The plan shall explain the basis for stopping operation of the PM CEMS and propose an alternative-monitoring plan. If the United States disapproves the alternative PM monitoring plan, or if the United States rejects EKPC's claim that it is infeasible to continue operating PM CEMS, such disagreement is subject to Section XVI (Dispute Resolution).

95. Operation of a PM CEMS shall be considered no longer feasible if (a) the PM CEMS cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol; or (b) EKPC demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If EPA determines that operation is no longer feasible, EKPC shall be entitled to discontinue operation of and remove the PM CEMS.

3. Mercury CEMS

96. EKPC shall install and operate Mercury CEMS in accordance with Paragraphs 97 through 102. The Mercury CEMS shall continuously measure mercury emission concentration, directly or indirectly, on an hourly average basis, in units of pounds per trillion BTU ("lb/TBTU"). EKPC shall maintain, in an electronic database, the hourly average emission

values of all Mercury CEMS in lb/TBTU. EKPC shall use reasonable efforts to keep each Mercury CEMS running and producing data whenever any Unit served by the Mercury CEMS is operating.

97. No later than six (6) months after entry of this Consent Decree, EKPC shall submit to EPA for review and approval pursuant to Section XIII (Review and Approval of Submittals) of this Consent Decree a plan for the installation and certification of the Mercury CEMS.

98. EKPC shall install, certify, and operate the Mercury CEMS on the following Unit in accordance with the following schedule:

Unit	Deadline to Commence Operation of Mercury CEMS
Spurlock 1 or 2	10/1/08

No later than six (6) months after entry of this Consent Decree, EKPC may submit to EPA for review and approval an alternative Unit on which to install the Mercury CEMS required by this Paragraph 98.

99. No later than one hundred twenty (120) days prior to the deadline to commence operation of each Mercury CEMS, EKPC shall submit to EPA for review and approval pursuant to Section XIII (Review and Approval of Submittals) of this Consent Decree a proposed QA/QC protocol that shall be followed in calibrating such Mercury CEMS. Following EPA's approval of the protocol, EKPC shall thereafter operate the Mercury CEMS in accordance with the approved protocol.

100. No later than ninety (90) days after EKPC begins operation of the Mercury CEMS, EKPC shall conduct tests of the Mercury CEMS to demonstrate compliance with the

Mercury CEMS installation and certification plan submitted to and approved by EPA in accordance with Paragraph 97.

101. EKPC shall operate the Mercury CEMS for at least two (2) years on the Unit specified in Paragraph 98. After two (2) years of operation, EKPC may attempt to demonstrate that it is infeasible to continue operating Mercury CEMS. As part of that demonstration, EKPC shall submit an alternative Mercury monitoring plan for review and approval by the United States. The plan shall explain the basis for stopping operation of the Mercury CEMS and propose an alternative-monitoring plan. If the EPA disapproves the alternative Mercury monitoring plan, or if the EPA rejects EKPC's claim that it is infeasible to continue operating Mercury CEMS, such disagreement is subject to Section XVI (Dispute Resolution).

102. Operation of a Mercury CEMS shall be considered no longer feasible if (a) the Mercury CEMS cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol; or (b) EKPC demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If EPA determines that operation is no longer feasible, EKPC shall be entitled to discontinue operation of and remove the Mercury CEMS.

4. PM and Mercury Reporting

103. Following the installation of each PM and Mercury CEMS, EKPC shall begin and continue to report to EPA, pursuant to Section XII (Periodic Reporting), the data recorded by the PM and Mercury CEMS, expressed in lb/mmBTU and lb/TBTU, respectively, on a 3-hour, 24-hour, 30-day, and 365-day rolling average basis in electronic format, as required in Paragraphs 88 and 96.

D. General PM Provisions

104. Although stack testing shall be used to determine compliance with the PM Emission Rate established by this Consent Decree, data from the PM CEMS shall be used, at a minimum, to monitor progress in reducing PM emissions. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8315 (Feb. 27, 1997)) concerning the use of data for any purpose under the Act, generated either by the reference methods specified herein or otherwise.

VIII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

105. Emission reductions generated by EKPC to comply with the requirements of this Consent Decree shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's Nonattainment NSR and PSD programs.

106. The limitations on the generation and use of netting credits or offsets set forth in the previous Paragraph 105 do not apply to emission reductions achieved by EKPC System Units that are greater than those required under this Consent Decree. For purposes of this Paragraph 106, emission reductions from an EKPC System Unit are greater than those required under this Consent Decree if they result from EKPC compliance with federally-enforceable emission limits that are more stringent than those limits imposed on EKPC System Units under this Consent Decree and under applicable provisions of the Clean Air Act or the Kentucky SIP.

107. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by the Commonwealth of Kentucky or EPA as creditable contemporaneous emission decreases for the purpose of attainment

demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS, PSD increment, or air quality related values, including visibility, in a Class I area.

IX. ENVIRONMENTAL PROJECTS

108. EKPC shall implement the Environmental Project ("Project") described in Appendix A in compliance with the approved plans and schedules for such Project and other terms of this Consent Decree. EKPC shall submit plans for the Project to the United States for review and approval pursuant to Section XIII (Review and Approval of Submittals) of this Consent Decree in accordance with the schedules set forth in Appendix A. EKPC shall maintain, and present to the United States, upon request, all documents to substantiate the cost of the Project and shall provide these documents to the United States within thirty (30) days of a request by the United States for the documents.

109. All plans and reports prepared by EKPC pursuant to the requirements of this Section of the Consent Decree shall be publicly available without charge.

110. EKPC shall certify, as part of each plan submitted to the United States for any Project, that EKPC is not otherwise required by law to perform the Project described in the plan, that EKPC is unaware of any other person who is required by law to perform the Project, and that EKPC will not use any Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law, including any applicable renewable portfolio standards.

111. EKPC shall use good faith efforts to secure as much benefit as possible for the Project, consistent with the applicable requirements and limits of this Consent Decree.

112. If EKPC elects (where such an election is allowed) to undertake a Project by contributing funds to another person or instrumentality that will carry out the Project, that person or instrumentality must in writing: (a) identify its legal authority for accepting such funding; and (b) identify its legal authority to conduct the Project for which EKPC contributes the funds. Regardless of whether EKPC elected (where such election is allowed) to undertake a Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, EKPC acknowledges that it will receive credit for the expenditure of such funds only if EKPC demonstrates that the funds have been actually spent by either EKPC or by the person or instrumentality receiving them (or, in the case of internal costs, have actually been incurred by EKPC), and that such expenditures met all requirements of this Consent Decree.

113. Within sixty (60) days following the completion of the Project required under this Consent Decree, EKPC shall submit to the United States a report that documents the date that the Project was completed, EKPC's results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the costs incurred by EKPC in implementing the Project.

114. EKPC shall not financially benefit to a greater extent than any other member of the general public from the sale or transfer of technology obtained in the course of implementing any Project.

115. Beginning one (1) year after entry of this Consent Decree, EKPC shall provide the United States with semi-annual updates concerning the progress of each Project.

X. CIVIL PENALTY

116. Within thirty (30) calendar days after entry of this Consent Decree, EKPC shall pay to the United States a civil penalty in the amount of $750,000. The civil penalty shall be

paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 2007Z00290 and 2004V00107 and DOJ Case Number 90-5-2-1-08085 and the civil action case name and case number of this action. The costs of such EFT shall be EKPC's responsibility. Payment shall be made in accordance with instructions provided to EKPC by the Financial Litigation Unit of the U.S. Attorney's Office for the Eastern District of Kentucky, Lexington Division. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, EKPC shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action case name and case number, to the Department of Justice and to EPA in accordance with Section XIX (Notices) of this Consent Decree.

117. Failure to timely pay the civil penalty shall subject EKPC to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render EKPC liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

118. Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

XI. RESOLUTION OF CLAIMS

A. <u>RESOLUTION OF U.S. CIVIL CLAIMS</u>

119. <u>Claims Based on Modifications Occurring Before the Lodging of Decree</u>.

Entry of this Decree shall resolve all civil claims of the United States under either:

a. Parts C or D of Subchapter I of the Clean Air Act,

b. Section 111 of the Clean Air Act and 40 C.F.R. Section 60.14,

c. Sections 502(a) and 504(a) of the Clean Air Act, but only to the extent that such claims are either (i) based on EKPC's failure to obtain an operating permit that reflects applicable requirements imposed under Parts C or D of Subchapter I, or Section 111, of the Clean Air Act; or (ii) EKPC's operation of Spurlock 2 at a heat input above that listed in the 1982 Spurlock Operating Permit No. 0-82-270 and 1999 Spurlock Title V permit V-97-050,

d. 401 KAR 51:017 and all relevant prior versions of these regulations,

e. 401 KAR 52:020 and all relevant prior versions of these regulations, but only to the extent that such claims are based on either (i) EKPC's failure to obtain an operating permit that reflects applicable requirements imposed under 401 KAR 51:017, or (ii) EKPC's operation of Spurlock 2 at a heat input above that listed in the 1982 Spurlock Operating Permit No. 0-82-270 and 1999 Spurlock Title V permit V-97-050,

that arose from any modifications that commenced at any EKPC System Unit prior to the date of lodging of this Decree, including but not limited to those modifications alleged in the Complaint in this civil action.

120. Claims Based on Modifications After the Lodging of Decree.

Entry of this Decree also shall resolve all civil claims of the United States for pollutants regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder as of the date of lodging of this Decree, where such claims are based on a modification completed before December 31, 2015 and:

a. commenced at any EKPC System Unit after lodging of this Decree; or

b. that this Consent Decree expressly directs EKPC to undertake.

The term "modification" as used in this Paragraph 120 shall have the meaning that term is given under the Clean Air Act statute as it existed on the date of lodging of this Decree.

121. Reopener. The resolution of the civil claims of the United States provided by this Subsection is subject to the provisions of Section B of this Section.

B. PURSUIT OF U.S. CIVIL CLAIMS OTHERWISE RESOLVED

122. Bases for Pursuing Resolved Claims Across EKPC System. If EKPC violates Paragraph 57 (System-wide NO_x Rolling Tonnage Limits); Paragraph 68 (System-wide SO_2 Rolling Tonnage Limits); or Paragraph 78 (Fuel Limitations); exceeds any 30-Day Rolling Average Emission Rate or 30-Day Rolling Average SO_2 Removal Efficiency for more than 60 consecutive days, or fails by more than ninety days to complete installation or upgrade and commence operation of any emission control device required pursuant to Paragraphs 51, 52, 53, 64, or 65; or fails by more than ninety days to retire and permanently cease to operate or Re-power EKPC System Units pursuant to Paragraph 50, then the United States may pursue any claim at any EKPC System Unit that is otherwise covered by the resolution of claims under Subsection A of this Section, subject to (a) and (b) below.

a. For any claims based on modifications undertaken at an Other Unit (any EKPC System Unit that is not an Improved Unit for the pollutant in question), claims may be pursued only where the modification(s) on which such claim is based was commenced within the five (5) years preceding the violation or failure specified in this Paragraph 122.

b. For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced (i) after lodging of the Consent Decree and (ii) within the five years preceding the violation or failure specified in this Paragraph 122.

123. Additional Bases for Pursuing Resolved Claims for Modifications at an Improved Unit. Solely with respect to Improved Units, the United States may also pursue claims arising from a modification (or collection of modifications) at an Improved Unit that are otherwise covered by the resolution of claims under Subsection A of this Section, if the modification (or collection of modifications) at the Improved Unit on which such claims are based (i) was commenced after lodging of this Consent Decree, and (ii) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

124. Additional Bases for Pursuing Resolved Claims for Modifications at an Other Unit. Solely with respect to Other Units, the United States may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that are otherwise covered by the resolution of claims under Subsection (a) of this Section, if the modification (or collection of modifications) at the Other Unit on which the claim is based was commenced within the five (5) years preceding any of the following events:

a. a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree increases the maximum hourly emission rate for such Other Unit for the relevant pollutant (NO_x or SO_2) (as measured by 40 C.F.R. § 60.14(b) and (h));

b. the aggregate of all Capital Expenditures made at such Other Unit exceed $125/KW on the Unit's Boiler Island (based on the generating capacities identified in Paragraph 12 or 13) during either of the following periods: the date of lodging of this Decree through December 31, 2010; January 1, 2011 through December 31, 2015. (Capital Expenditures shall be measured in calendar year

2004 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

c. a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree results in an emissions increase of NO_x and/or SO_2 at such Other Unit, and such increase:

i. presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603;

ii. causes or contributes to violation of a NAAQS in any Air Quality Control Area that is in attainment with that NAAQS;

iii. causes or contributes to violation of a PSD increment; or

iv. causes or contributes to any adverse impact on any formally-recognized air quality and related values in any Class I area.

d. Solely for purposes of Paragraph 124, Subparagraph (c), the determination of whether there was an emissions increase must take into account any emissions changes relevant to the modeling domain that have occurred or will occur under this Decree at other EKPC System Units. In addition, an emissions increase shall not be deemed to have occurred at an Other Unit unless the annual emissions of the relevant pollutant (NO_x or SO_2) from the plant at which such modification(s) occurred exceed the annual emissions from that plant for calendar year 2003.

e. The introduction of any new or changed NAAQS shall not, standing alone, provide the showing needed under Paragraph 124, Subparagraphs (c)(ii) or (c)(iii), to pursue any claim for a modification at an Other Unit resolved under Subsection A of this Section.

XII. PERIODIC REPORTING

125. Within one hundred eighty (180) days after each date established by Paragraphs 51, 52, 53, 64 and 65 of this Consent Decree for EKPC to achieve and maintain a certain Emission Rate or 30-Day Rolling Average SO_2 Removal Efficiency at any EKPC System Unit, EKPC shall conduct a performance test that demonstrates compliance with the Emission Rate or Removal Efficiency required by this Consent Decree. Within forty-five (45) days of each such performance test, EKPC shall submit the results of the performance test to EPA at the addresses specified in Section XIX (Notices) of this Consent Decree.

126. Beginning thirty (30) days after the end of the first full calendar quarter following the entry of this Consent Decree, continuing on a semi-annual basis until December 31, 2015, and in addition to any other express reporting requirement in this Consent Decree, EKPC shall submit to EPA a progress report.

127. The progress report shall contain the following information:

a. all information necessary to determine compliance with this Consent Decree;

b. all information relating to emission allowances and credits that EKPC claims to have generated in accordance with Paragraphs 61 or 76 by compliance beyond the requirements of this Consent Decree; and

c. all information indicating that the installation and commencement of operation for a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by EKPC to mitigate such delay.

128. In any periodic progress report submitted pursuant to this Section, EKPC may incorporate by reference information previously submitted under its Title V permitting requirements, provided that EKPC attaches the Title V permit report and provides a specific reference to the provisions of the Title V permit report that are responsive to the information required in the periodic progress report.

129. In addition to the progress reports required pursuant to this Section, EKPC shall provide a written report to EPA of any violation of the requirements of this Consent Decree, including exceedances of the Unit-specific 30-Day Rolling Average Emission Rates, Unit-specific 30-Day Rolling Average SO_2 Removal Efficiencies, Combined 30-Day Rolling Average Emission Rate, 1-Hour Average NO_x Emission Rate, and System-Wide 12-Month Rolling Tonnage limitations, within ten (10) business days of when EKPC knew or should have known of any such violation. In this report, EKPC shall explain the cause or causes of the violation and all measures taken or to be taken by EKPC to prevent such violations in the future.

130. Each EKPC report shall be signed by EKPC's Environmental Manager, or, in his or her absence, the Vice President for Generation and Transmission Operations, or higher ranking official, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

131. If any allowances are surrendered to any third party pursuant to Section VI.C (Surrender of SO_2 Allowances) of this Consent Decree, the third party's certification pursuant to Paragraph 73 shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that,____________ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

XIII. REVIEW AND APPROVAL OF SUBMITTALS

132. EKPC shall submit each plan, report, or other submission to EPA whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. EPA may approve the submittal or decline to approve it and provide written comments. Within sixty (60) days of receiving written comments from EPA, EKPC shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal for final approval to EPA; or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XVI (Dispute Resolution) of this Consent Decree.

133. Upon receipt of EPA's final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, EKPC shall implement the approved submittal in accordance with the schedule specified therein.

XIV. STIPULATED PENALTIES

134. For any failure by EKPC to comply with the terms of this Consent Decree, and subject to the provisions of Sections XV (Force Majeure) and XVI (Dispute Resolution), EKPC

shall pay, within thirty (30) days after receipt of written demand to EKPC by the United States, the following stipulated penalties to the United States:

Consent Decree Violation	**Stipulated Penalty (Per day per violation, unless otherwise specified)**
a. Failure to pay the civil penalty as specified in Section X (Civil Penalty) of this Consent Decree	$10,000
b. Failure to comply with any applicable Combined 30-Day Rolling Average Emission Rate for NO_x, 30-Day Rolling Average Emission Rate for NO_x or SO_2, 30-Day Rolling Average SO_2 Removal Efficiency, or Emission Rate for PM, where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500
c. Failure to comply with any applicable Combined 30-Day Rolling Average Emission Rate for NO_x, 30-Day Rolling Average Emission Rate for NO_x or SO_2, 30-Day Rolling Average SO_2 Removal Efficiency, or Emission Rate for PM, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000
d. Failure to comply with any applicable Combined 30-Day Rolling Average Emission Rate for NO_x, 30-Day Rolling Average Emission Rate for NO_x or SO_2, 30-Day Rolling Average SO_2 Removal Efficiency, or Emission Rate for PM, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000
e. Failure to comply with any 1-Hour Average NO_x Emission Rate, where the violation is equal to or less than 3 ppm.	$1000 per violation
f. Failure to comply with any 1-Hour Average NO_x Emission Rate, where the violation is greater than 3 ppm.	$5000 per violation
g. Reserved.	Reserved.
h. Failure to comply with the System-wide 12-Month Rolling SO_2 and NO_x Tonnage Limits	$5,000 per ton per month for the first 100 tons over the limit, and $10,000 per ton per month for each additional ton over the limit
i. Failure to install, commence operation, or continue operation of the NO_x, SO_2, and PM pollution control devices on any Unit, or failure to retire a Unit	$10,000 during the first 30 days, $27,500 thereafter
j. Failure to comply with the fuel limitations at a unit, as required by Paragraph 78	$10,000

k. Failure to install or operate CEMS as required in Paragraphs 88 through 102	$1,000
l. Failure to conduct annual or biennial stack tests of PM emissions, as required in Paragraph 86	$1,000
m. Failure to apply for any permit required by Section XVII	$1,000
n. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree	$750 during the first ten days, $1,000 thereafter
o. Using, selling, or transferring SO_2 Allowances, except as permitted by Paragraphs 71, 72, and 76	the surrender, pursuant to the procedures set forth in Paragraphs 70, 73, and 74 of this Consent Decree, of SO_2 Allowances in an amount equal to four times the number of SO_2 Allowances used, sold, or transferred in violation of this Consent Decree
p. Using, selling or transferring NO_x Allowances except as permitted by Paragraphs 59, 60 and 61	the surrender of NO_x Allowances in an amount equal to four times the number of NO_x Allowances used, sold, or transferred in violation of this Consent Decree
q. Failure to surrender an SO_2 Allowance as required by Paragraph 72	(a) $27,500 plus (b) $1,000 per SO_2 Allowance
r. Failure to demonstrate the third-party surrender of an SO_2 Allowance in accordance with Paragraph 73	$2,500
s. Failure to undertake and complete any of the Environmental Projects in compliance with Section IX (Environmental Projects) of this Consent Decree	$1,000 during the first 30 days, $5,000 thereafter
t. Any other violation of this Consent Decree	$1,000

135. Violation of an Emission Rate or removal efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based. Violation of

System-Wide 12-Month Rolling Tonnage limitations is a violation each month on which the average is based.

136. Where a violation of a 30-Day Rolling Average Emission Rate or 30-Day Rolling Average SO_2 Removal Efficiency (for the same pollutant and from the same source) recurs within periods of less than thirty (30) days, EKPC shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

137. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

138. EKPC shall pay all stipulated penalties to the United States within thirty (30) days of receipt of written demand to EKPC from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s) no longer continues, unless EKPC elects within 20 days of receipt of written demand to EKPC from the United States to dispute the accrual of stipulated penalties in accordance with the provisions in Section XVI (Dispute Resolution) of this Consent Decree.

139. Stipulated penalties shall continue to accrue as provided in accordance with Paragraph 137 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement, or by a decision of Plaintiffs pursuant to Section XVI (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid within thirty (30) days of the effective date of the agreement or of the receipt of EPA's decision;

b. If the dispute is appealed to the Court and Plaintiffs prevail in whole or in part, EKPC shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with accrued interest, except as provided in Subparagraph 139.c.;

c. If the Court's decision is appealed by either Party, EKPC shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued stipulated penalties determined to be owing, together with accrued interest.

For purposes of this Paragraph, the accrued stipulated penalties agreed by the Parties, or determined by the Plaintiffs through Dispute Resolution, to be owing may be less than the stipulated penalty amounts set forth in Paragraph 134.

140. All stipulated penalties shall be paid in the manner set forth in Section X (Civil Penalty) of this Consent Decree.

141. Should EKPC fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

142. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States by reason of EKPC's failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree provides for payment of a stipulated

penalty, EKPC shall be allowed a credit for stipulated penalties paid against any statutory penalties also imposed for such violation.

XV. FORCE MAJEURE

143. For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of EKPC, its contractors, or any entity controlled by EKPC that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite EKPC's best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

144. Notice of Force Majeure Events. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which EKPC intends to assert a claim of Force Majeure, EKPC shall notify the United States in writing as soon as practicable, but in no event later than twenty-one (21) days following the date that the event occurred. In this notice, EKPC shall reference this Paragraph 144 of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by EKPC to prevent or minimize the delay or violation, the schedule by which EKPC proposes to implement those measures, and EKPC's rationale for attributing a delay or violation to a Force Majeure Event. EKPC shall adopt all reasonable measures to avoid or minimize such delays or violations. EKPC shall be deemed to know of any circumstance which EKPC, its contractors, or any entity controlled by EKPC knew.

145. Failure to Give Notice. If EKPC fails to comply with the notice requirements of this Section, the Plaintiff may void EKPC's claim for Force Majeure as to the specific event for which EKPC has failed to comply with such notice requirement.

146. Plaintiff's Response. The Plaintiff shall notify EKPC in writing regarding EKPC's claim of Force Majeure within twenty (20) business days of receipt of the notice provided under Paragraph 144. If the Plaintiff agrees that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XXIII (Modification) of this Consent Decree.

147. Disagreement. If the Plaintiff does not accept EKPC's claim of Force Majeure, or if the Parties cannot agree on the length of the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section XVI (Dispute Resolution) of this Consent Decree.

148. Burden of Proof. In any dispute regarding Force Majeure, EKPC shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. EKPC shall also bear the burden of proving that EKPC gave the notice required by this Section and the burden of proving the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

149. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of EKPC's obligations under this Consent Decree shall not constitute a Force Majeure Event.

150. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and EKPC's response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; natural gas supply interruption; acts of God; acts of war or terrorism; and orders by a government official, government agency, or other regulatory body acting under and authorized by applicable law that directs EKPC to supply electricity in response to a system-wide (state-wide or regional) emergency. Depending upon the circumstances and EKPC's response to such circumstances, failure of a permitting authority or the Kentucky Public Service Commission to issue a necessary permit or order with sufficient time for EKPC to achieve compliance with the requirements of this Consent Decree may constitute a Force Majeure Event where the failure of the authority to act is beyond the control of EKPC and EKPC has taken all steps available to it to obtain the necessary permit or order, including, but not limited to: submitting a complete application or request; responding to requests for additional information by the authority in a timely fashion; and accepting lawful terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the authority.

151. As part of the resolution of any matter submitted to this Court under Section XVI (Dispute Resolution) of this Consent Decree regarding a claim of Force Majeure, the Parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work

that occurred as a result of any delay agreed to by the United States or approved by the Court. EKPC shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

152. Malfunction Events. If EKPC intends to exclude a period of Malfunction, as defined in Paragraph 22, from the calculation of any 30-Day Rolling Average Emission Rate, Combined 30-Day Rolling Average Emission Rate, or 30-Day Rolling Average SO_2 Removal Efficiency, EKPC shall notify the United States in writing as soon as practicable, but in no event later than twenty one (21) days following the date the Malfunction occurs.

a. In this notice, EKPC shall describe the anticipated length of time that the Malfunction may persist, the cause or causes of the Malfunction, all measures taken or to be taken by EKPC to minimize the duration of the Malfunction, and the schedule by which EKPC proposes to implement those measures. EKPC shall adopt all reasonable measures to minimize the duration of such Malfunctions, and to prevent the recurrence of such Malfunctions in the future.

b. A Malfunction, as defined in Paragraph 22 of this Consent Decree, does not constitute a Force Majeure Event unless the Malfunction also meets the definition of a Force Majeure Event, as provided in this Section. Conversely, a period of Malfunction may be excluded by EKPC from the calculations of emission rates and removal efficiencies, as allowed under this Paragraph, regardless of whether the Malfunction constitutes a Force Majeure Event.

XVI. DISPUTE RESOLUTION

153. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Party.

154. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Party advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Party receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

155. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting among the disputing Parties' representatives unless they agree in writing to shorten or extend this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually-agreed-upon alternative dispute resolution (ADR) forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period (or such longer period as the Parties may agree to in writing).

156. If the disputing Parties are unable to reach agreement during the informal negotiation period, the EPA shall provide EKPC with a written summary of their position regarding the dispute. The written position provided by EPA shall be considered binding unless, within forty-five (45) calendar days thereafter, EKPC seeks judicial resolution of the dispute by filing a petition with this Court. The EPA may respond to the petition within forty-five (45) calendar days of filing.

157. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the Parties to the dispute.

158. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

159. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. EKPC shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule, provided that EKPC shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

160. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 156, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

XVII. PERMITS

161. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires EKPC to secure a permit to authorize construction or operation of any device, including all preconstruction, construction, and operating permits required under state law, EKPC shall make such application in a timely

manner. EPA will use its best efforts to expeditiously review all permit applications submitted by EKPC in order to meet the requirements of this Consent Decree.

162. Notwithstanding Paragraph 161, nothing in this Consent Decree shall be construed to require EKPC to apply for or obtain a PSD or Nonattainment NSR permit for physical changes in, or changes in the method of operation of, any EKPC System Unit that would give rise to claims resolved by Section XI (Resolution of Claims) of this Consent Decree.

163. When permits are required as described in Paragraph 161, EKPC shall complete and submit applications for such permits to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request, including requests for additional information by the permitting authorities. Any failure by EKPC to submit a timely permit application for any EKPC System Unit shall bar any use by EKPC of Section XV (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

164. Notwithstanding the reference to Title V or other federally enforceable permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V or other federally enforceable permits shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term has or will become part of a Title V or other federally enforceable permit, subject to the terms of Section XXVII (Conditional Termination of Enforcement Under Decree) of this Consent Decree.

165. Within one hundred eighty (180) days after entry of this Consent Decree, EKPC shall apply for amendment of its Title V permit for the Spurlock Plant to incorporate an MCR of 5600 mmBTU/hr for Spurlock Unit 2. EPA will use its best efforts to expeditiously review such

application submitted by EKPC and will not object to amendment of EKPC's Title V permit for the Spurlock Plant to specify an MCR of 5600 mmBTU/hr for Spurlock Unit 2.

166. Within one hundred eighty (180) days after entry of this Consent Decree, EKPC shall amend any applicable Title V permit application, or apply for amendments of its Title V permits, to include a schedule for all Unit-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, emission rates, removal efficiencies, fuel limitations, tonnage limitations, and the requirement in Paragraph 72 pertaining to the surrender of SO_2 Allowances.

167. Within one (1) year from the commencement of operation of each pollution control device to be installed, upgraded, or operated on an Improved Unit under this Consent Decree, EKPC shall apply to include the requirements and limitations enumerated in this Consent Decree in either a federally enforceable operating permit issued under the Kentucky SIP or amendments to the Kentucky SIP. The permit or SIP amendment shall require compliance with the following: (a) any applicable 30-Day Rolling Average Emission Rate, 1-Hour Average NO_x Emission Rate, or 30-Day Rolling Average SO_2 Removal Efficiency, (b) the allowance surrender requirements set forth in this Consent Decree, and (c) any applicable tonnage limitations set forth in this Consent Decree.

168. Prior to January 1, 2015, EKPC shall either: (a) apply for a federally enforceable operating permit issued under the Kentucky SIP for each plant in the EKPC System to include a provision, which shall be identical for each permit, that contains the allowance surrender requirements and the System-Wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree; or (b) apply for amendments to the Kentucky SIP to include such requirements and limitations. If EKPC elects to apply for a federally enforceable permit, or if EKPC applies to amend the Kentucky SIP on a plant-specific basis, then EKPC shall include a provision in

each such application that makes violation of the allowance surrender requirements and System-Wide 12-Month Rolling Tonnage limitations a violation of each permit, or plant-specific Kentucky SIP provision, for each plant in the EKPC System to which such requirements apply.

169. For each EKPC System Unit, EKPC shall provide EPA with a copy of each application for a permit to address or comply with any provision of this Consent Decree, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment opportunity.

170. If EKPC sells or transfers to an entity unrelated to EKPC ("Third Party Purchaser") part or all of its Ownership Interest in a EKPC System Unit covered under this Consent Decree, EKPC shall comply with the requirements of Paragraphs 166 through 168 with regard to that Unit prior to any such sale or transfer unless, following any such sale or transfer, EKPC remains the holder of the Title V or other federally enforceable permit for such facility.

XVIII. INFORMATION COLLECTION AND RETENTION

171. Any authorized representative of the United States or Permitting State Agency, including their attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the EKPC System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by EKPC or its representatives, contractors, or consultants; and

d. assessing EKPC's compliance with this Consent Decree.

172. EKPC shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in its or its contractors' or agents' possession or control, and that directly relate to EKPC's performance of its obligations under this Consent Decree for the following periods: (a) until December 31, 2020 for records concerning modifications undertaken in accordance with Paragraph 120; and (b) until December 31, 2017 for all other records. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

173. All information and documents submitted by EKPC pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of documents unless (a) the information and documents are subject to legal privileges or protection or (b) EKPC claims and substantiates in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

174. Nothing in this Consent Decree shall limit the authority of the EPA to conduct tests and inspections at EKPC's facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations or permits.

XIX. NOTICES

175. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

<u>As to the United States of America:</u>

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-08085

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.W.
Atlanta, Georgia 30303-8960

<u>As to EKPC</u>:

Environmental Manager
East Kentucky Power Cooperative
4775 Lexington Road
PO Box 707
Winchester, KY 40392-0707

and

General Counsel
East Kentucky Power Cooperative
4775 Lexington Road
PO Box 707
Winchester, KY 40392-0707

176. All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or delivery service; (b) certified or registered mail, return receipt requested; or (c) electronic transmission, unless the recipient is not able to review the transmission in electronic form. All notifications, communications and transmissions (a) sent

by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked, or (b) sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service. All notifications, communications, and submissions made by electronic means shall be electronically signed and certified, and shall be deemed submitted on the date that EKPC receives written acknowledgment of receipt of such transmission.

177. Either Party may change either the notice recipient or the address for providing notices to it by serving the other Party with a notice setting forth such new notice recipient or address.

XX. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

178. If EKPC proposes to sell or transfer an Ownership Interest to a Third Party Purchaser, it shall advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the Plaintiff pursuant to Section XIX (Notices) of this Consent Decree at least sixty (60) days before such proposed sale or transfer.

179. No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and EPA have executed, and the Court has approved, a modification pursuant to Section XXIII (Modification) of this Consent Decree making the Third Party Purchaser a party defendant to this Consent Decree and jointly and severally liable with EKPC for all the requirements of this Decree that may be applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 181.

180. This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between EKPC and any Third Party Purchaser as long the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a

contractual allocation – as between EKPC and any Third Party Purchaser of Ownership Interests – of the burdens of compliance with this Decree, provided that both EKPC and such Third Party Purchaser shall remain jointly and severally liable to EPA for the obligations of the Decree applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 181.

181. If EPA agrees, EPA, EKPC, and the Third Party Purchaser that has become a party defendant to this Consent Decree pursuant to Paragraph 179, may execute a modification that relieves EKPC of its liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests. Notwithstanding the foregoing, however, EKPC may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections IX (Environmental Projects) and X (Civil Penalty). EKPC may propose and the EPA may agree to restrict the scope of joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the transferred or purchased Ownership Interests, to the extent such obligations may be adequately separated in an enforceable manner.

XXI. EFFECTIVE DATE

182. The effective date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

XXII. RETENTION OF JURISDICTION

183. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree,

either Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXIII. MODIFICATION

184. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by both Parties. Where the modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court.

XXIV. GENERAL PROVISIONS

185. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The emission rates set forth herein do not relieve EKPC from any obligation to comply with other state and federal requirements under the Clean Air Act, including EKPC's obligation to satisfy any state modeling requirements set forth in the Kentucky SIP.

186. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

187. In any subsequent administrative or judicial action initiated by the United States for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, EKPC shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph 187 is intended to affect the validity of Section XI (Resolution of Claims).

188. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve EKPC of its obligation to comply with all applicable federal, state, and local

laws and regulations. Subject to the provisions in Section XI (Resolution of Claims), nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the United States to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

189. Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree and, except as otherwise provided in this Decree, every other term used in this Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Decree what such term means under the Act or those implementing regulations.

190. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8315 (Feb. 27, 1997)) concerning the use of data for any purpose under the Act, generated either by the reference methods specified herein or otherwise.

191. Each limit and/or other requirement established by or under this Decree is a separate, independent requirement.

192. Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. EKPC shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending upon whether the limit is expressed to three or two significant digits. For example, if an actual Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an

Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. EKPC shall report data to the number of significant digits in which the standard or limit is expressed.

193. This Consent Decree does not limit, enlarge or affect the rights of either Party to this Consent Decree as against any third parties.

194. This Consent Decree constitutes the final, complete and exclusive agreement and understanding between the Parties with respect to the settlement embodied in this Consent Decree, and supercedes all prior agreements and understandings between the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

195. Each Party to this action shall bear its own costs and attorneys' fees.

XXV. SIGNATORIES AND SERVICE

196. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

197. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

198. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXVI. PUBLIC COMMENT

199. The Parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper or inadequate. EKPC shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified EKPC, in writing, that the United States no longer supports entry of the Consent Decree.

XXVII. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

200. Termination as to Completed Tasks. As soon as EKPC completes a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, EKPC may, by motion to this Court, seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

201. Conditional Termination of Enforcement Through the Consent Decree. After EKPC:

a. has successfully completed construction, and has maintained operation, of all pollution controls as required by this Consent Decree;

b. has obtained final Title V permits and has obtained federally enforceable permits or SIP amendments (i) as required by the terms of this Consent Decree; (ii) that cover all units in this Consent Decree; and (iii) that include as enforceable permit terms all of the unit performance and other requirements specified in Section XVII (Permits) of this Consent Decree; and

c. certifies that the date is later than December 31, 2015;

then EKPC may so certify these facts to the Plaintiff and this Court. If the Plaintiff does not object in writing with specific reasons within forty-five (45) days of receipt of EKPC's certification, then, for any Consent Decree violations that occur after EKPC's certification, the Plaintiff shall pursue enforcement of the requirements contained in the Title V or other federally enforceable permit through the permit and not through this Consent Decree.

202. Resort to Enforcement under this Consent Decree. Notwithstanding Paragraph 201, if enforcement of a provision in this Decree cannot be pursued by a Party under the applicable Title V permit, or if a Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Decree at any time.

XXVIII. FINAL JUDGMENT

203. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment in the above-captioned matter between the Plaintiff and EKPC.

SO ORDERED, THIS _____ DAY OF ________________, 2007.

____

THE HONORABLE KARL S. FORESTER
UNITED STATES DISTRICT COURT JUDGE

Signature Page for Consent Decree in:

United States of America
v.
East Kentucky Power Cooperative, No. 04-34-KSF (E.D. Ky.)

FOR THE UNITED STATES OF AMERICA:

RONALD J. TENPAS
Acting Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice

PHILLIP A. BROOKS
Counsel to the Chief
JASON A. DUNN
Trial Attorney
Environmental Enforcement Section
Environment and Natural Resources Division
United States Department of Justice

Signature Page for Consent Decree in:

United States of America
v.
East Kentucky Power Cooperative, No. 04-34-KSF (E.D. Ky.)

ANDREW SPARKS
Assistant United States Attorney
Eastern District of Kentucky
United States Department of Justice

Signature Page for Consent Decree in:

United States of America
v.
East Kentucky Power Cooperative, No. 04-34-KSF (E.D. Ky.)

CATHERINE R. MCCABE
Principal Deputy Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

ADAM M. KUSHNER
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

ANDREW C. HANSON
Attorney Advisor
Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Signature Page for Consent Decree in:

United States of America
v.
East Kentucky Power Cooperative, No. 04-34-KSF (E.D. Ky.)

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Atlanta, GA 30303

Signature Page for Consent Decree in:

United States of America
v.
East Kentucky Power Cooperative, No. 04-34-KSF (E.D. Ky.)

FOR DEFENDANT EAST KENTUCKY POWER COOPERATIVE:

ROBERT MARSHALL
President & CEO
East Kentucky Power Cooperative

APPENDIX A - ENVIRONMENTAL PROJECTS REQUIREMENTS

In compliance with and in addition to the requirements in Section IX of the Consent Decree, EKPC shall comply with the requirements of this Appendix to ensure that the benefits of the Environmental Project is achieved.

I. Spurlock Plant Wet Electrostatic Precipitator Project

A. Within sixty days of entry of the Consent Decree, EKPC shall submit a plan to the Plaintiff for review and approval for the performance of the Spurlock Plant Wet Electrostatic Precipitators (WESP) Project. The project will result in the installation of WESPs that will control sulfuric acid emissions from Spurlock Units 1 and 2, with a goal of achieving an emissions rate no greater than 0.005 lbs sulfuric acid mist per mmBTU heat input. EKPC shall install and operate the Spurlock Unit 1 and 2 WESPs on the same schedule as is required for the Spurlock Unit 1 and 2 FGDs pursuant to Paragraph 64 of this Consent Decree. EKPC shall install, operate and maintain the WESPs in accordance with manufacturers' specifications and good engineering practices, so as to minimize emissions to the maximum extent practicable. For purposes of the Consent Decree, the expected $47 million capital cost for construction and installation of the WESPs shall be deemed to satisfy the Environmental Projects requirements of Section IX upon commencement of operation of this control technology, provided that EKPC continues to operate the control technology for at least five (5) years.

B. The proposed plan shall satisfy the following criteria:

1. Describe how the work or project to be performed is consistent with the requirements of Section I.A, above.
2. Include a general schedule and budget for completion of the construction of the WESPs, along with a plan for the submittal of periodic reports to the Plaintiff on the progress of the work through completion of the construction and operation of the WESPs.
3. Require at a minimum that the WESPs be designed to achieve an emissions rate no greater than 0.020 lbs sulfuric acid mist per mmBTU heat input.
4. Require that EKPC shall provide the Plaintiff, upon completion of the construction and continuing annually thereafter, with the results of annual stack tests performed pursuant to 40 C.F.R. Appendix A, Method 8. EKPC shall, in accordance with manufacturers' specifications and good engineering practices, operate the WESPs so as to minimize emissions to the maximum extent practicable and so as to meet the emission rate goal set forth in the proposed plan, and in any event shall demonstrate in such annual stack tests an emissions rate no greater than 0.020 lbs sulfuric acid mist per mmBTU heat input.
5. Describe generally the expected environmental benefit for the project.

C. Performance - Upon approval of the plan by the Plaintiff, EKPC shall complete the Spurlock WESP Project according to the approved plan and schedule.

Cooper / Dale Study Report

October 31, 2008

Prepared by:

East Kentucky Power Cooperative
Resource Planning
Winchester, KY 40391

Cooper/Dale Study Report

1.0 Executive Summary

East Kentucky Power Cooperative ("EKPC") entered into a Consent Decree ("CD") with the United States Environmental Protection Agency ("EPA") in 2007. In the CD, the EPA gave EKPC the option to either install and continuously operate NOx and SO_2 emission controls at Cooper Unit 2 or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012. EKPC also has the option of repowering Dale Units 3 and 4 by May 31, 2014. The decision to either install new emission controls at Cooper Unit 2 or retire Dale Units 3 and 4 must be submitted in writing to the EPA no later than December 21, 2009. Based on this stipulation, EKPC initiated a study to evaluate its options. Burns & McDonnell Engineering Company was hired to provide plant evaluations and develop specific cost and operating characteristics for each viable option available to EKPC. Eight options were developed and analyzed. In addition to the economic impacts, significant operational concerns and consideration of potential future environmental regulations were driving factors in the decision making process. EKPC's conclusion of the analysis was that construction of emission controls at Cooper Station was the best long term alternative for EKPC and its member systems. This report describes the analyses that were completed and describes how EKPC reached its conclusion.

2.0 Background

EKPC contracted with Burns & McDonnell Engineering Company (Burns & McDonnell) to perform a Power Plant Assessment Study (Study), attached to this report after page 42. The main objective of this Study was to develop detailed cost and operating characteristics of each option available to EKPC relating to the CD. This CD has resulted in constraints placed on emission rates of nitrogen oxides (NOx), sulfur dioxide (SO_2), and particulate matter (PM). In addition, EKPC will monitor mercury levels. In the CD, the EPA alleges that EKPC failed to obtain the necessary permits and install the controls necessary under the Clean Air Act to reduce its sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that EKPC violated various operating permit conditions. EKPC has denied and continues to deny the violations alleged in the Complaint, however, EKPC has agreed to the obligations in the CD to avoid the costs and uncertainties of litigation and to improve the environment.

In the CD, the EPA has given EKPC the option to either install and continuously operate NOx and SO_2 emission controls at Cooper Unit 2 or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012. EKPC does have the option of repowering Dale Units 3 and 4 by May 31, 2014. The decision to either install new emission controls at Cooper Unit 2 or retire Dale Units 3 and 4 must be submitted in writing to the EPA no later than December 21, 2009.

The Consent Decree is applicable to only those units defined as "system" units. Spurlock 1 and 2, Cooper 1 and 2, and Dale 3 and 4 were defined as "system" units. The Consent Decree has several requirements which are applicable to all "system" units.

1. NOx CEMS
2. SO_2 CEMS
3. Annual PM stack test
4. PM control device to achieve 0.030 lb/MMBtu emission rate
5. Low NOx burners
6. System-wide NOx and SO_2 limits

NOx and SO_2 CEMS must be installed and continually operated on every "system" unit. Emission rates measured by the CEMS will be used to determine NOx and SO_2 compliance in accordance with 40 CFR Part 75 and the CD. An annual PM stack test is required for each EKPC unit. Any stack test performed to comply with a permit for the Kentucky Natural Resources and Environmental Protection Cabinet may be used to satisfy the CD requirement. The results of the stack test must be submitted to the EPA within 30 days of completion of each test. A biannual stack test may be substituted for the annual test providing that:

- The two most recent tests are less than or equal to 0.015 lb/MMBtu, or
- The Unit is equipped with a PM CEMS.

EKPC is to install and operate a PM control device on each "system" unit. EKPC may elect to upgrade existing PM control devices. If an upgrade is desired, a PM Pollution Control Upgrade Analysis is required unless it is a complete replacement of an existing device or the cost of refurbishing an existing device costs equal to or more than a complete replacement (on a total dollar-per-ton-of-pollutant-removed basis).

A number of different options were considered in meeting the obligations of the CD. Four options relating to Cooper Station and four options relating to Dale Station were considered. Burns & McDonnell developed performance data, capital cost estimates, and operation and maintenance cost estimates of each option. This data is explained in the Burns & McDonnell "Report on the Power Plant Assessment Study for the East Kentucky Power Cooperative", Project Number 46644, completed in 2007 and attached as reference to this EKPC report.

Burns & McDonnell developed data for the following options:

A. Cooper 2 Dry Scrubber
B. Cooper 2 Wet Scrubber
C. Cooper 1&2 Wet Scrubbers
D. Cooper 1&2 Repower with CFB
E. Retire Dale 1-4
F. Repower Dale 3&4 with Combined Cycle (2-1x1 7FA)
G. Repower Dale 3&4 with Combined Cycle (2-1x1 7EA)
H. Repower Dale 3&4 with CFB

Burns & McDonnell also developed a simplified busbar analysis in order to provide an economic ranking of each option. This analysis was for simple screening only; it did not incorporate overall EKPC system impacts, detailed financial analysis, detailed production costing analysis, risk or uncertainty analysis. EKPC utilized the Burns & McDonnell report data as input for a separate detailed cost study, which is documented in this EKPC report.

3.0 Case Assumptions

EKPC utilized the data developed by Burns & McDonnell for each of the eight cases, as described in the following.

Dry Scrubber (SDA) added to Cooper Unit 2
In this case, a SCR (for NOx control) and a dry scrubber (SDA, for SO_2 control) are added to Cooper Unit 2. The SCR must be in operation by December 31, 2012 and the SDA must be in operation by August 30, 2012. Cooper Unit 1 continues to operate as before and a CEMS is added to both units.

The dry scrubber must achieve an emission rate of 0.100 lb SO_2/MMBtu (30-day rolling average) or achieve at least 95% reduction in SO_2 emissions. The scrubber must be operational by June 30, 2012. Compliance must be demonstrated in part through an SO_2 CEMS. Additionally, the system-wide SO_2 12month rolling tonnage limits must be met. A removal percentage of 95% may be difficult to maintain on a long-term basis with a dry scrubber, depending upon the selected technology.

This option would likely require permitting for the new particulate emissions associated with the scrubber (material transfer and hauling of lime/limestone).

An SCR or equivalent NOx control device must achieve an emission rate of 0.080 lb/MMBtu or better and be in operation by December 31, 2012. A PM control device must achieve an emission rate of 0.030 lb/MMBtu and a PM CEMS must be installed.

Table 3-1
Case A – Cooper Unit 2 SDA

		Avg Sulfur	High Sulfur	
PERFORMANCE	Total Nameplate Capacity	220	220	(MW)
	Plant Net Heat Rate	10,240	10,240	(Btu/kWh)
CAPITAL COST	NO_x emissions controls (SCR)	$59,455,761	$59,445,367	(2007$)
	SO_2 emission controls (SDA)	$167,506,185	$214,361,293	(2007$)
	Stack breakout – included with SDA	$17,255,000	$17,439,000	(2007$)
	Booster Fan breakout – incl. w/SDA	$5,144,891	$5,241,293	(2007$)
	PM emission controls – Fabric Filter	$65,732,511	$70,128,495	(2007$)
	Total Capital Requirement (TCR)	$292,694,457	$343,935,155	(2007$)
	Total Project Cost (per Total Capacity)	$1,330	$1,563	(2007$/kW)
O & M COSTS	Total Fixed O&M – Existing Plant	2.21	2.21	(2007$/MWh)
	Variable O&M – Existing Plant	11.32	11.32	(2007$/MWh)
	Fuel – Existing Plant	23.58	23.58	(2007$/MWh)
	NO_x emissions controls (SCR)	$2,599,121	$2,598,755	(2007$/yr)
	SO_2 emission controls (SDA)	$12,524,178	$23,372,773	(2007$/yr)
	Stack breakout – included with SDA	$166,142	$167,913	(2007$/yr)
	Booster Fan breakout – incl. w/SDA	$35,279	$35,940	(2007$/yr)
	PM emission controls – Fabric Filter	$1,302,836	$1,371,974	(2007$/yr)
	Total O&M Costs for Pollution Control	$16,426,135	$27,343,502	(2007$/yr)

Wet Scrubber (WFGD) added to Cooper Unit 2

This case is identical to previous case except that a wet scrubber (WFGD) is installed rather than a dry scrubber (SDA). Like the dry scrubber case, the SCR must be in operation by December 31, 2012 and the WFGD must be in operation by August 30, 2012. Cooper Unit 1 continues to operate as before and a continuous emissions monitoring system is added to both units.

The wet scrubber must achieve an emission rate of 0.100 lb SO_2/MMBtu (30-day rolling average) or achieve at least 95% reduction in SO_2 emissions. The scrubber must be operation by June 30, 2012. Compliance must be demonstrated in part through an SO_2 CEMS. Additionally, the system-wide SO_2 12-month rolling tonnage limits must be met.

This option would likely require permitting for the new particulate emissions associated with the scrubber (material transfer and hauling of lime/limestone) since the PSD major source threshold is only 15 tpy.

An SCR or equivalent NOx control device must achieve an emission rate of 0.080 lb/MMBtu or better and be in operation by December 31, 2012, A PM control device must achieve an emission rate of 0.030 lb/MMBtu and a PM CEMS must be installed.

Table 3-2
Case B – Cooper Unit 2 WFGD

		Avg Sulfur	High Sulfur	
PERFORMANCE	Total Nameplate Capacity	220	220	(MW)
	Plant Net Heat Rate	10,240	10,240	(Btu/kWh)
CAPITAL COST	NO_x emissions controls (SCR)	$59,455,761	$59,445,266	(2007$)
	SO_2 emission controls (WFGD)	$247,704,308	$257,912,941	(2007$)
	Stack breakout – included with WFGD	$20,490,000	$20,588,000	(2007$)
	Booster Fan breakout – incl. w/WFGD	$6,921,548	$6,919,930	(2007$)
	PM emission controls – Fabric Filter	$689,370	$689,370	(2007$)
	Total Capital Requirement (TCR)	$307,849,439	$318,047,578	(2007$)
	Total Project Cost (per Total Capacity)	$1,399	$1,446	(2007$/kW)
O & M COSTS	Total fixed O&M – Existing Plant	2.21	2.21	(2007$/MWh)
	Variable O&M – Existing Plant	11.32	11.32	(2007$/MWh)
	Fuel – Existing Plant	23.58	23.58	(2007$/MWh)
	NO_x emissions controls (SCR)	$2,599,121	$2,598,755	(2007$/yr)
	SO_2 emission controls (WFGD)	$9,895,843	$13,177,708	(2007$/yr)
	Stack breakout – included with WFGD	$246,372	$247,551	(2007$/yr)
	Booster Fan breakout – incl. w/WFGD	$71,193	$71,176	(2007$/yr)
	PM emission controls – Fabric Filter	$955,834	$947,369	(2007$/yr)
	Total O&M Costs for Pollution Control	$13,450,798	$16,723,826	(2007$/yr)

Wet Scrubbers (WFGD) added to Cooper Units 1 and 2

In this option a wet scrubber (WFGD) is sized and added to support both Cooper Unit 1 and Cooper Unit 2. In this way, Cooper Unit 1 and Cooper Unit 2 basically operate as a single unit, which means that the total rating of this "combined" system is about 340MW. Again, the SCR must be in operation by December 31, 2012 and the WFGD must be in operation by August 30, 2012. A continuous emission monitoring system is added to both units.

The wet scrubber must achieve an emission rate of 0.100 lb SO_2/MMBtu (30-day rolling average) or achieve at least 95% reduction in SO_2 emissions. Obtaining the required control efficiency will be easier with a wet scrubber than a dry scrubber. The scrubber must be operational by June 30, 2012. Compliance must be demonstrated in part through an SO_2 CEMS. Additionally, the system-wide SO_2 12-month rolling tonnage limits must be met.

Since controlling Cooper Unit 1 as well as Cooper Unit 2 is beyond the scope of the consent order, the emissions reductions from the control of Cooper Unit 1 would be available as allowances for other units in the EKPC system or to be sold per paragraph 77d of the CD.

Table 3-3
Case C – Cooper Units 1& 2 WFGD

		Avg Sulfur	High Sulfur	
PERFORMANCE	Total Nameplate Capacity	341	341	(MW)
	Plant Net Heat Rate	10,240	10,240	(Btu/kWh)
CAPITAL COST	NO_x emissions controls (SCR)	$97,550,617	$97,533,732	(2007$)
	SO_2 emission controls (WFGD)	$291,027,851	$304,943,632	(2007$)
	Stack breakout – included with WFGD	$26,080,406	$26,205,223	(2007$)
	Booster Fan breakout – incl. w/WFGD	$9,146,525	$9,144,387	(2007$)
	PM emission controls – Fabric Filter	$95,507,151	$95,385,300	(2007$)
	Total Capital Requirement (TCR)	$484,085,619	$497,862,664	(2007$)
	Total Project Cost (per Total Capacity)	$1,420	$1,460	(2007$/kW)
O & M COSTS	Total fixed O&M – Existing Plant	2.21	2.21	(2007$/MWh)
	Variable O&M – Existing Plant	11.32	11.32	(2007$/MWh)
	Fuel – Existing Plant	23.58	23.58	(2007$/MWh)
	NO_x emissions controls (SCR)	$4,027,521	$4,026,949	(2007$/yr)
	SO_2 emission controls (WFGD)	$13,276,629	$18,185,027	(2007$/yr)
	Stack breakout – included with WFGD	$288,891	$290,273	(2007$/yr)
	Booster Fan breakout – incl. w/WFGD	$94,079	$94,057	(2007$/yr)
	PM emission controls – Fabric Filter	$1,355,912	$1,343,208	(2007$/yr)
	Total O&M Costs for Pollution Control	$18,660,062	$35,555,184	(2007$/yr)

Cooper Unit 2 Repowered with a Circulating Fluidized Bed (CFB) Unit

This case assumes that Cooper Unit 2 is repowered with a like-sized (250 MW) Circulating Fluidized Bed (CFB) unit.

If EKPC decides to repower Cooper Unit 2 with a CFB, a Prevention of Significant Deterioration (PSD) permit will be required, including Best Available Control Technology (BACT) determination and dispersion modeling. BACT would be set more stringent than 0.100 lb SO_2/MMBtu or 95% reduction. The decrease of SO_2 from 0.100 lb SO_2/MMBtu or 95% to the lower BACT level can be sold or transferred per paragraph 77c of the CD, after meeting the system-wide SO_2 requirements.

Table 3-4
Case D – Cooper Unit 2 Repower with CFB

PERFORMANCE	Total Nameplate Capacity	250	(MW)
	Plant Net Heat Rate	10,240	(Btu/kWh)
CAPITAL COST	Equipment cost (1)	$200,000,000	(2007$)
	Construction / Erection Costs	$50,000,000	(2007$)
	SNCR / Baghouse (2)	$0	(2007$)
	Civil / Electrical / Other BOP	$24,000,000	(2007$)
	Engineering / Project Management	$45,000,000	(2007$)
	Coal / Limestone Handling / Storage (3)	$17,000,000	(2007$)
	Project Indirects & Owner's Cost	$55,000,000	(2007$)
	Total Cost w/out IDC	$391,000,000	(2007$)
	Interest During Construction	$27,370,000	(2007$)
	Contingency	$62,755,500	(2007$)
	Total Project Cost	$481,125,500	(2007$)
	Total Project Cost (per Total Capacity)	$1,925	(2007$/kW)
O & M COSTS	Total Fixed O&M	2.21	(2007$/MWh)
	Variable O&M	5.35	(2007$/MWh)

(1) This includes the CFB boiler, boiler steel, coal mills, SNCR, Flash dryer, Baghouse, Limestone system, Limestone silos in boiler house, coal silos in boiler house (from Alstom)
(2) SNCR and Baghouse are included in Equipment Cost
(3) Silos are included in Equipment Cost

Retire Dale Units 1-4

In this case all four units at Dale are retired. This must be accomplished on or before December 31, 2012 to comply with the CD. Cooper Units 1 and 2 continue to operate as usual with continuous emissions monitoring devices added to both units. The only capital costs required in this case are for renumeration costs. It is assumed in the economic analysis that the capacity and energy from the Dale Units will be made up of power purchases from the adjacent power markets. Although the CD applies only to Dale Units 3 and 4, due to the small size of Dale Units 1 and 2, it was assumed that it would not be feasible to keep the Dale Plant running just for these two units, so all four units were assumed to be retired.

If EKPC decides to retire Dale Units 1, 2, 3, and 4, no environmental permits would be required. Since retiring all four (4) units is beyond the scope of the consent order, the emissions reductions from Dale Units 1 and 2 would be available as allowances for other units in the EKPC system or to be sold per paragraph 77d of the CD.

Table 3-5
Case E – Retire Dale Units 1-4

PERFORMANCE	Total Project Capacity	N/A	(MW)
	New Project Capacity	N/A	(MW)
	Heat Rate – Full Load w/out Duct Firing	N/A	(Btu/kWh)
	Heat Rate – 75% Load	N/A	(Btu/kWh)
CAPITAL COST	Capital Cost	$0	(2007$)
	Project Indirects & Owner's Cost	$0	(2007$)
	Site Renumeration Costs	$9,308,400	(2007$)
	Total Cost w/out IDC	$9,308,400	(2007$)
	Interest During Construction	$0	(2007$)
	Total Project Cost	$9,308,400	(2007$)
O & M COSTS	Total Fixed O&M (excl. property tax/insurance	0	(2007$/kW-yr)
	Variable O&M (excl. Major Maintenance)	0	(2007$/MWh)

Repower Dale Units 3-4 with 2-1on1 7FA Combined Cycle Units

This case assumes repowering of Dale Units 3 and 4 is performed per the CD with a two 1 on 1 General Electric 7FA combustion turbines operating in combined cycle mode. This will add approximately 330 MW to the existing 150 MW making the new capacity about 480 MW without any duct firing. The "new" existing steam turbines would be incorporated. Dale Units 1 and 2 and Cooper Units 1 and 2 would all continue to operate as usual. Burns & McDonnell assumed the repowered units would come on-line by 6/1/2014 and EKPC made the assumption they would come on-line by 1/1/2013. EKPC named its case F1 to reflect the difference from the original case F.

If EKPC decides to repower Dale Units 3 and 4 with a 7FA Combined Cycle, a PSD permit will be required, including BACT determination and dispersion modeling. BACT likely be 3 ppm NOx, installation of a SCR, and use of pipeline quality natural gas. However, a combined cycle would be less likely to be subject to lawsuits and delays from intervener groups than a coal-fired unit.

Additionally, a PM CEMS must be installed on Cooper Unit 1 and both Cooper Units 1 and 2 must comply with the following:

- NOx CEMS
- SO_2 CEMS
- Annual PM stack test
- PM control device to achieve 0.030 lb/MMBtu emission rate
- Low NOx burners
- System-wide NOx and SO_2 limits

Table 3-6
Case F1 – Dale Units 3 & 4 Repower (2 -1x1 CCGT 7FA)

PERFORMANCE	Total Project Capacity	480	(MW)
	New Project Capacity	330	(MW)
	Heat Rate – Full Load w/out Duct Firing	7,450	(Btu/kWh)
	Heat Rate – 75% Load	7,823	(Btu/kWh)
	Heat Rate – 50% Load	8,493	(Btu/kWh)
CAPITAL COST	Capital Cost	$245,600,000	(2007$)
	Project Indirects & Owner's Cost	$80,900,000	(2007$)
	Site Renumeration Costs	$2,717,670	(2007$)
	Total Cost w/out IDC	$329,217,670	(2007$)
	Interest During Construction	$22,100,000	(2007$)
	Total Project Cost	$351,317,670	(2007$)
	Total Project Cost (per Total Capacity)	732	(2007$/kW)
O & M COSTS	Total Fixed O&M (excl. property tax/insurance	$3,600,000	(2007$/yr)
	Variable O&M (excl. Major Maintenance)	4.1	(2007$/MWh)
	GT Major Maintenance, Cost per Hour	$500	(2007$/hour)

Repower Dale Units 3-4 with 2-1on1 7EA Combined Cycle Units

This case assumes repowering of Dale Units 3 and 4 is performed per the CD with a two 1 on 1 General Electric 7EA combustion turbines operating in combined cycle mode. This will add approximately 170 MW to the existing 150 MW making the new capacity about 320 MW without any duct firing. The "new" existing steam turbines would be incorporated. Dale Units 1 and 2 and Cooper Units 1 and 2 would all continue to operate as usual. Burns & McDonnell assumed the repowered units would come on-line by 6/1/2014 and EKPC made the assumption they would come on-line by 1/1/2013. EKPC named its case G1 to reflect the difference from the original case G.

If EKPC decides to repower Dale Units 3 and 4 with a 7EA Combined Cycle, a PSD permit will be required, including BACT determination and dispersion modeling. BACT likely be 3 ppm NOx, installation of a SCR, and use of pipeline quality natural gas. However, a combined cycle would be less likely to be subject to lawsuits and delays from intervenor groups than a coal-fired unit.

Additionally, a PM CEMS must be installed on Cooper Unit 1 and both Cooper Units 1 and 2 must comply with the following:

- NOx CEMS
- SO_2 CEMS
- Annual PM stack test
- PM control device to achieve 0.030 lb/MMBtu emission rate
- Low NOx burners
- System-wide NOx and SO_2 limits

Table 3-7
Case G1 – Dale Units 3 & 4 Repower (2 -1x1 CCGT 7EA)

PERFORMANCE	Total Project Capacity	300	(MW)
	New Project Capacity	170	(MW)
	Heat Rate – Full Load w/out Duct Firing	8,500	(Btu/kWh)
CAPITAL COST	Capital Cost	$202,400,000	(2007$)
	Project Indirects & Owner's Cost	$76,500,000	(2007$)
	Site Renumeration Costs	$2,717,670	(2007$)
	Total Cost w/out IDC	$287,617,670	(2007$)
	Interest During Construction	$20,300,000	($)
	Total Project Cost	$301,917,670	(2007$)
	Total Project Cost (per Total Capacity)	$1,006	(2007$/kW)
O & M COSTS	Total Fixed O&M (excl. property tax/insurance	$3,600,000	(2007$/yr)
	Variable O&M (excl. Major Maintenance)	4.2	(2007$/MWh)
	GT Major Maintenance, Cost per Hour	$200	(2007$/hour)
	GT Major Maintenance, Cost per Start	$6,000	(2007$/start)

Repower Dale Units 3-4 with a Circulating Fluidized Bed (CFB) Unit

This case assumes repowering of Dale Units 3 and 4 is performed per the CD with a 150MW CFB unit. This keeps the output of the Dale station at about the same level as before the repowering. The "new" existing steam turbines would be incorporated. Dale Units 1 and 2 and Cooper Units 1 and 2 would all continue to operate as usual. Burns & McDonnell assumed the repowered units would come on-line by 6/1/2014 and EKPC made the assumption they would come on-line by 1/1/2013. EKPC named its case H1 to reflect the difference from the original case H.

If EKPC decides to repower Dale Units 3 and 4 with a CFB, a Prevention of Significant Deterioration (PSD) permit will be required, including Best Available Control Technology (BACT) determination and dispersion modeling. BACT would be set more stringent than 0.100 lb SO_2/MMBtu or 95% reduction. The decrease of SO_2 from 0.100 lb SO_2/MMBtu or 95% to the lower BACT level can be sold or transferred per paragraph 77c of the consent decree, after meeting the system-wide SO_2 requirements.

Additionally, a new coal-fired boiler would likely be subject to lawsuits and delays from intervenor groups. A new CFB would probably be subject to more public scrutiny than retrofitting the existing unit even though repowering would likely result in a greater decrease in overall emissions.

Additionally, a PM CEMS must be installed on Cooper Unit 1 and both Cooper Units 1 and 2 must comply with the following:

- NOx CEMS
- SO_2 CEMS
- Annual PM stack test
- PM control device to achieve 0.030 lb/MMBtu emission rate
- Low NOx burners
- System-wide NOx and SO_2 limits

Table 3-8
Case H1 – Dale Units 3 & 4 Repower with CFB

PERFORMANCE	Total Nameplate Capacity	144	(MW)
	Plant Heat Rate	11,038	(Btu/kWh)
CAPITAL COST	Capital cost (1)	$85,000,000	(2007$)
	Construction / Erection Costs	$31,000,000	(2007$)
	SNCR / Baghouse	$25,000,000	(2007$)
	Civil / Electrical / Other BOP	$13,500,000	(2007$)
	Engineering / Project Management	$35,000,000	(2007$)
	Coal / Limestone Handling / Storage	$24,000,000	(2007$)
	Project Indirects & Owner's Cost	$33,000,000	(2007$)
	Site Renumeration Costs	$6,082,800	(2007$)
	Total Cost w/out IDC	$252,582,800	(2007$)
	Interest During Construction	$17,680,796	(2007$)
	Contingency	$40,539,539	(2007$)
	Total Project Cost	$310,803,135	(2007$)
	Total Project Cost (per Total Capacity)	$2,158	(2007$/kW)
O & M COSTS	Total Fixed O&M	3.00	(2007$/MWh)
	Variable O&M	5.35	(2007$/MWh)

(4) The scope is boiler design engineering and supply with air fans and silo inlet to ID fan outlet. This design would include an allowance for adding some type of scrubber and a baghouse on the backend (from Foster Wheeler).

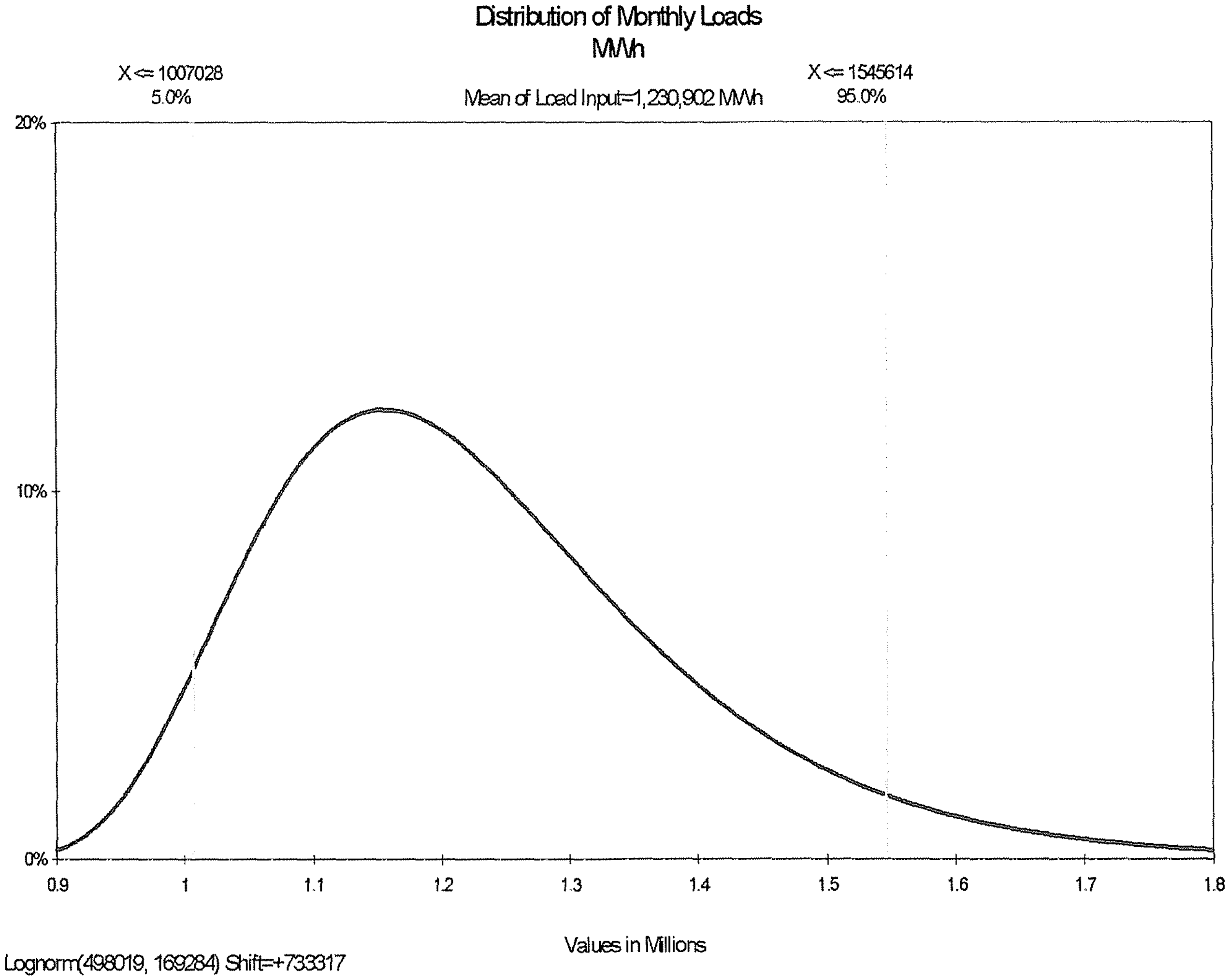
4.0 Methodology and Input Data

Study Methodology

EKPC used the RTSim production cost model to estimate 20 years of operating costs for each alternative. The model is capable of taking a range of values for each input parameter and running multiple iterations based on the input ranges to develop a risk adjusted expected value for each year and each alternative. EKPC modeled the entire system for each alternative in detail, developed expected operating costs, input those costs into a spreadsheet and added expected annual fixed operating and capital costs to the evaluation. Present worth analysis was then applied to these values to provide for meaningful comparisons. The following graphs are indicative of the range of input data that was utilized in the analysis. All graphs are based on data for 2012, each input assumption was adjusted to appropriate levels for each year of the analysis.

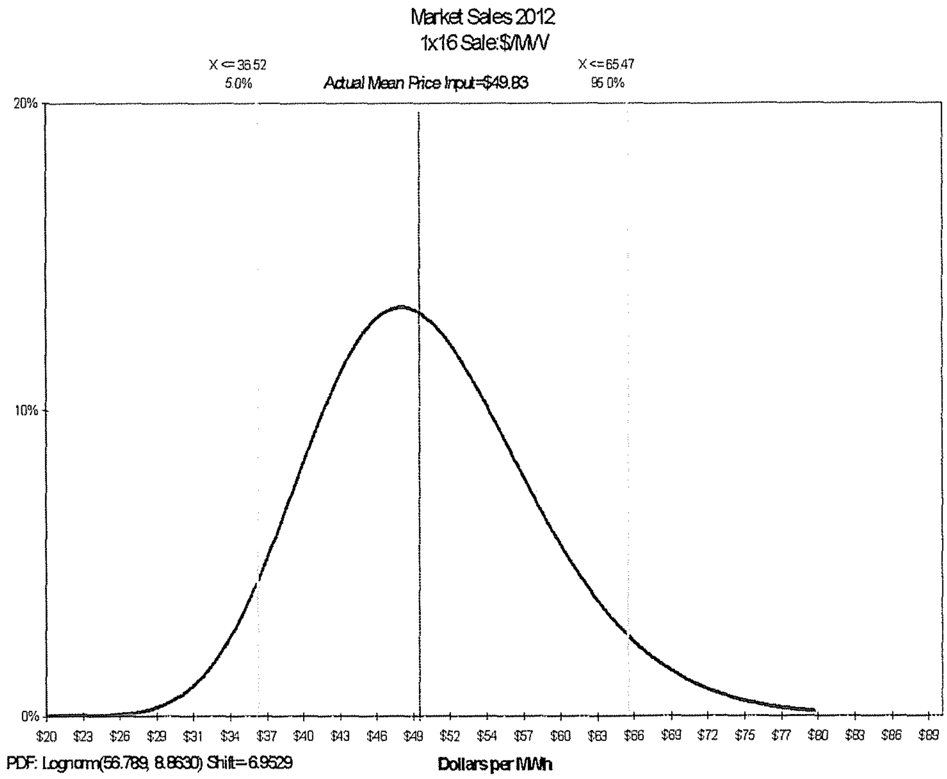
Loads

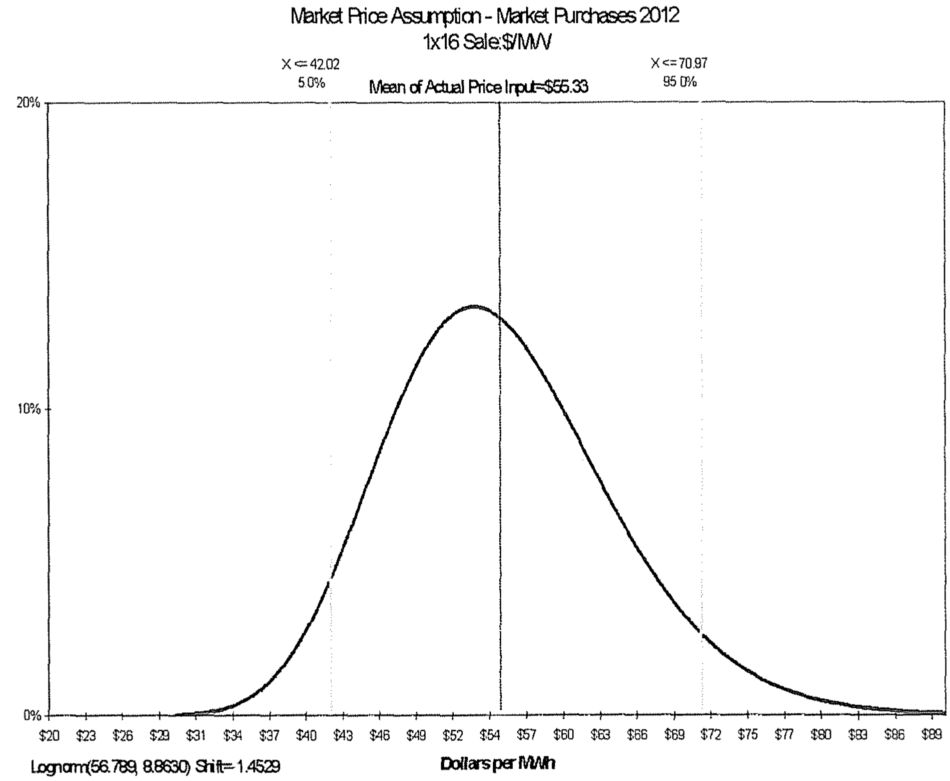
The EKPC load forecast, as approved by its Board in 2006, was utilized for the detailed system specific analysis. This data was developed utilizing Global Insight economic data and input from EKPC's member systems. The following distribution of monthly loads for 2012 was utilized.



Market Prices

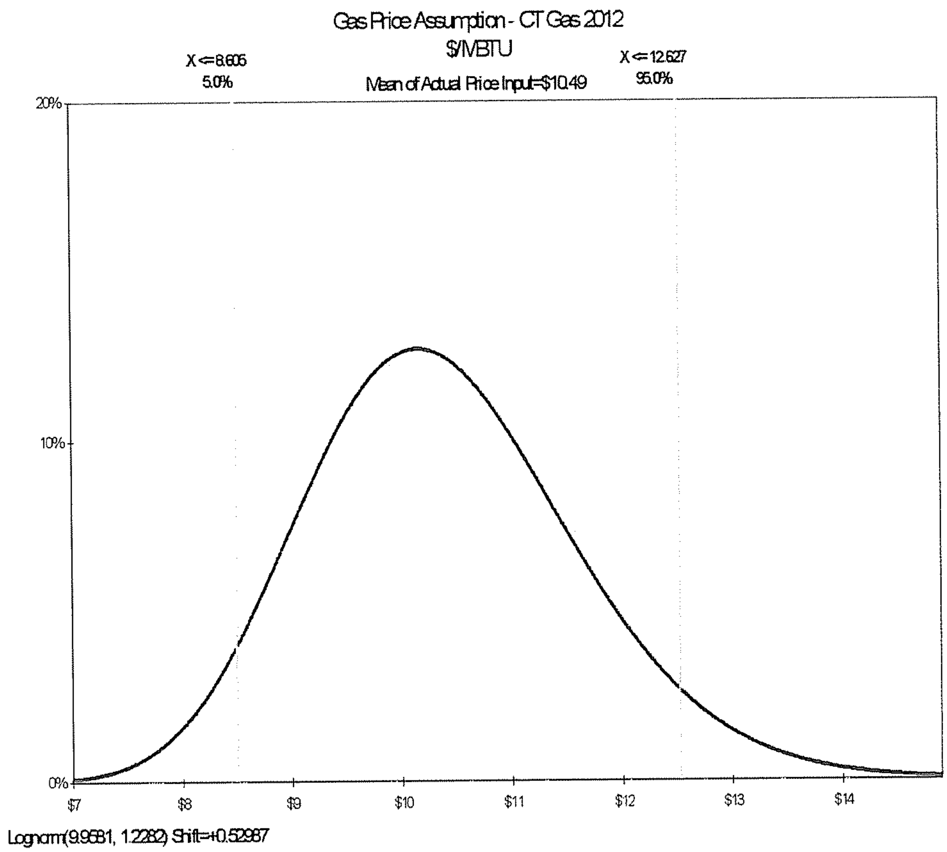
Market prices were based on data received from ACES Power Marketing and existing EKPC contracts.

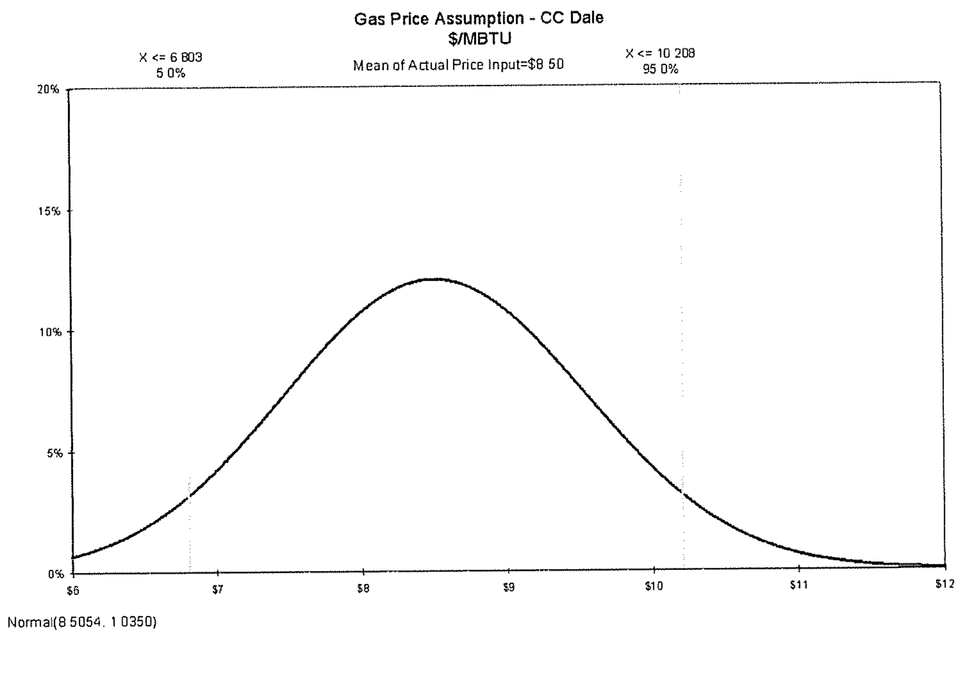


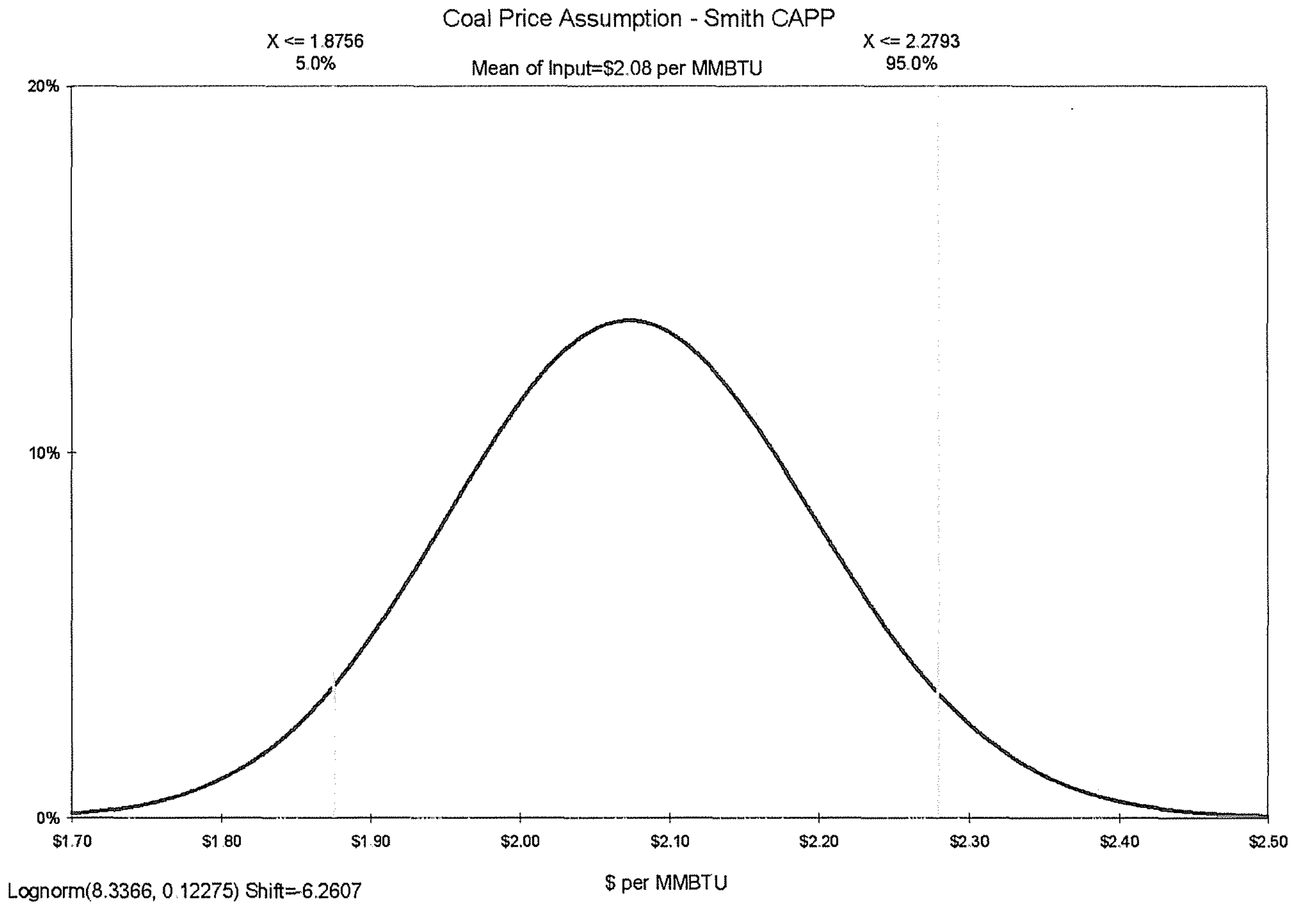


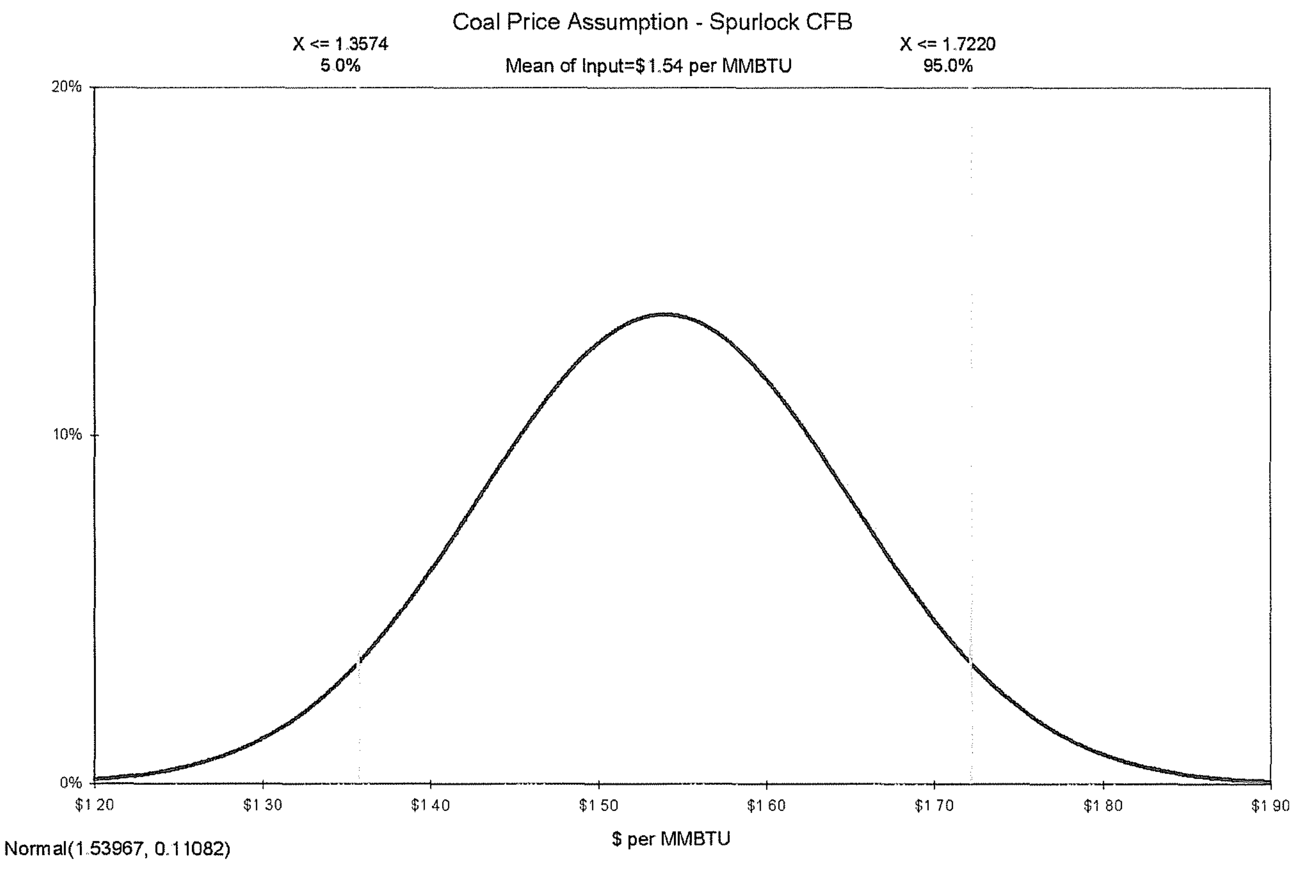
Fuel and Emission Prices

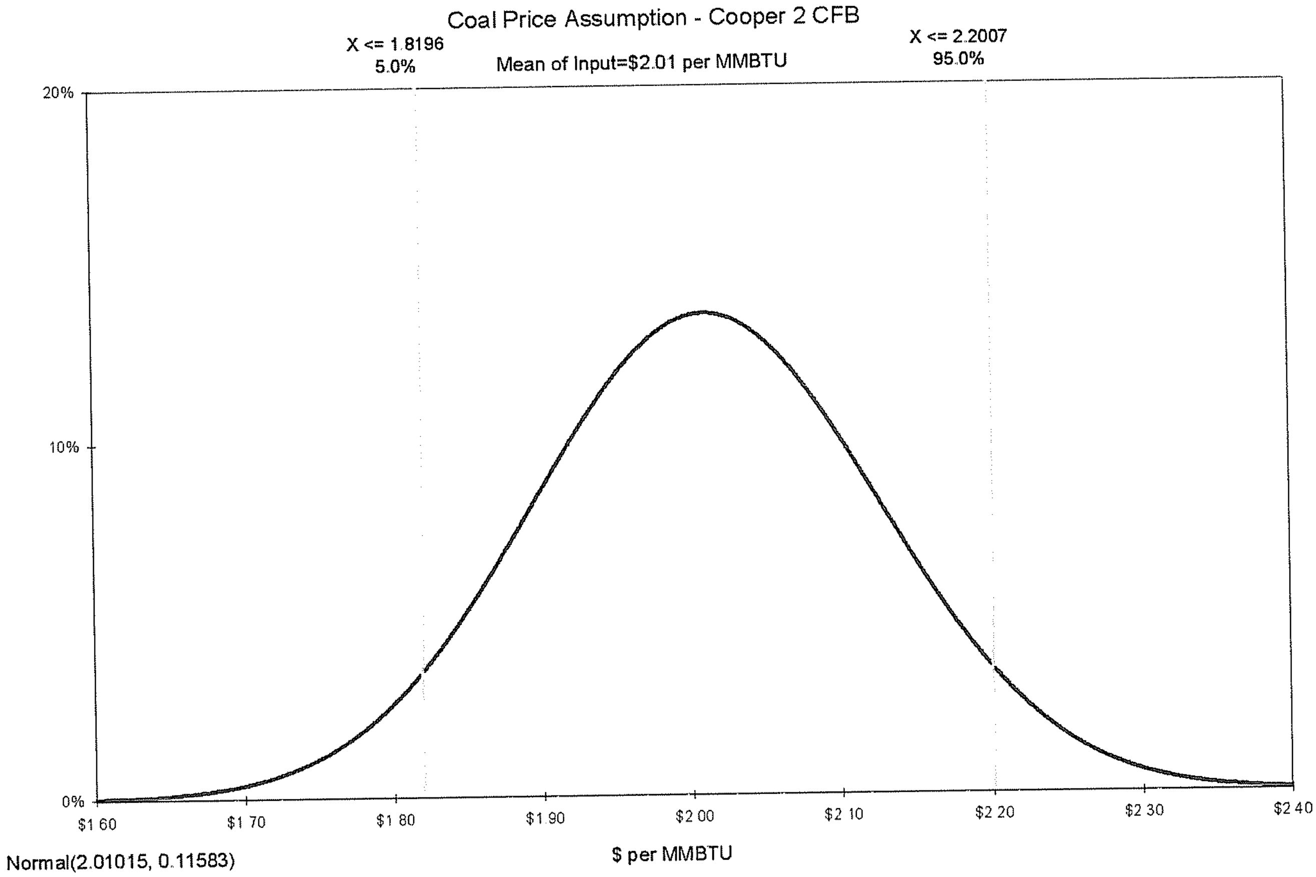
Fuel and emission prices were developed from information provided by the EKPC Fuels Department, EVA consultants, ACES Power Marketing, Hill and Associates consultants, and EIA reports. The following graphs depict the input data utilized in the study.

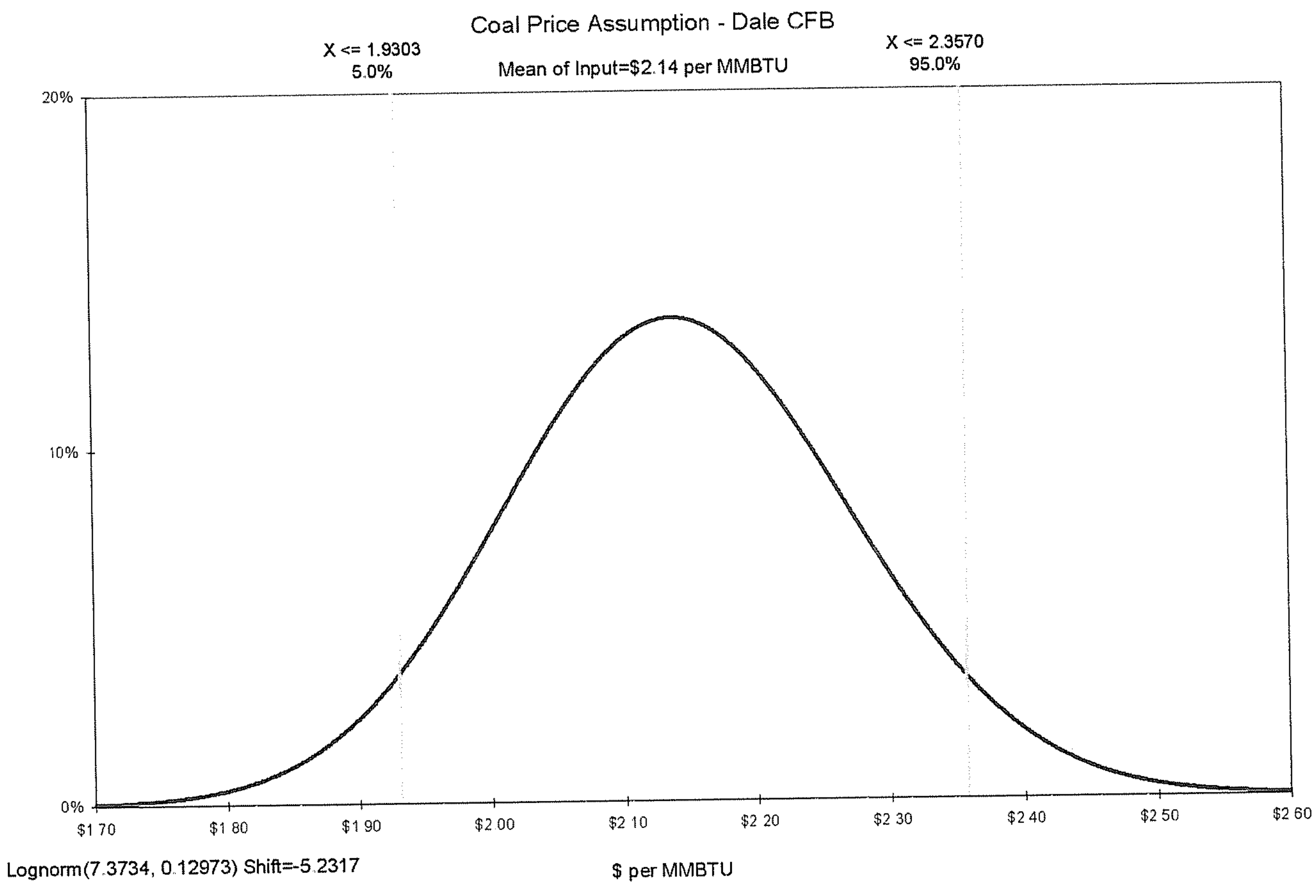


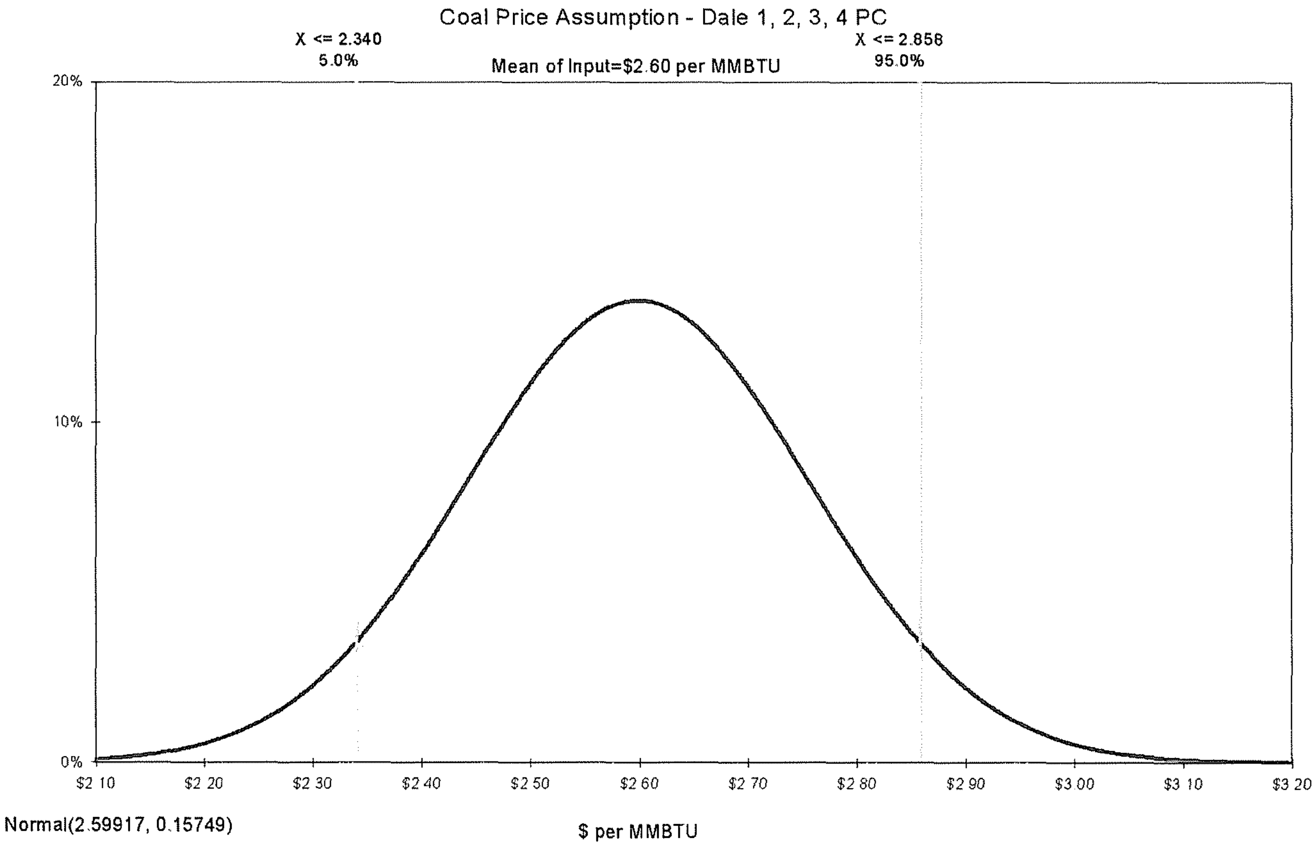


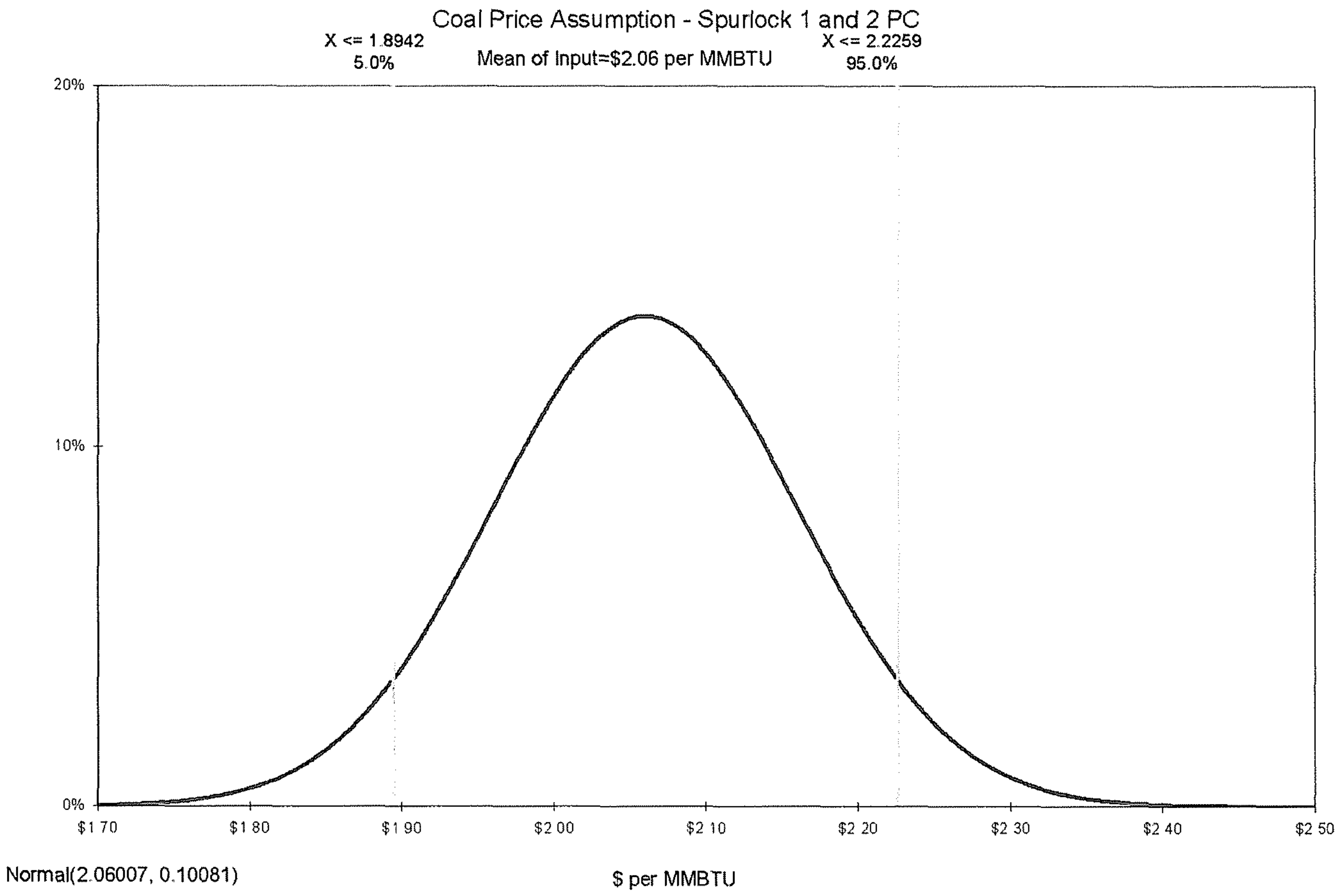

Coal Price Assumption - Smith CAPP
X <= 1.8756
5.0%
Mean of Input=$2.08 per MMBTU
X <= 2.2793
95.0%
20%
10%
0%
$1.70
$1 80
$1 90
$2.00
$2.10
$2.20
$2.30
$2.40
$2.50
$ per MMBTU
Lognorm(8.3366, 0 12275) Shift=-6.2607

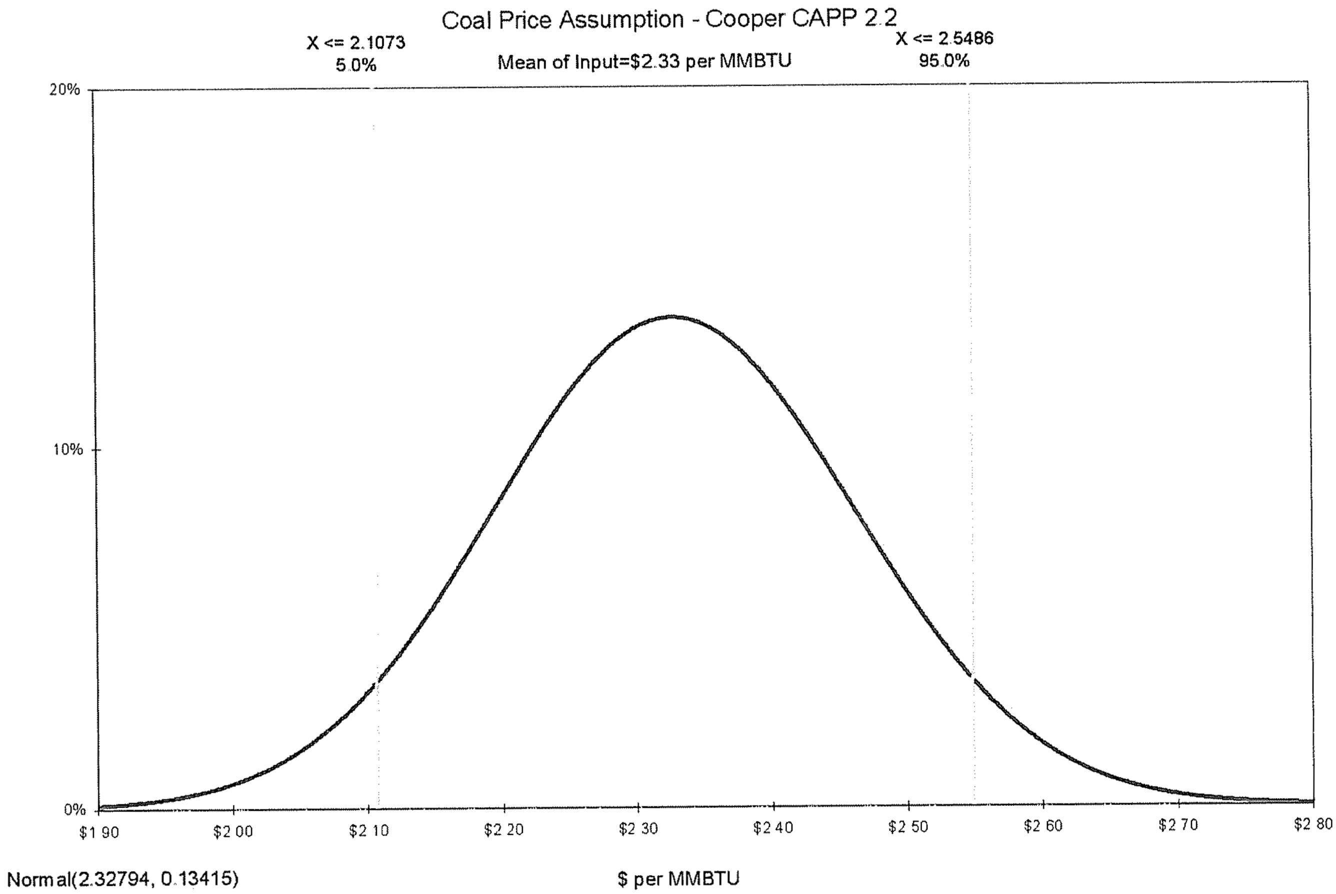

Coal Price Assumption - Spurlock CFB
X <= 1.3574
5 0%
Mean of Input=$1.54 per MMBTU
X <= 1.7220
95.0%
20%
10%
0%
$1 20
$1 30
$1 40
$1 50
$1 60
$1 70
$1 80
$1 90
$ per MMBTU
Normal(1.53967, 0.11082)

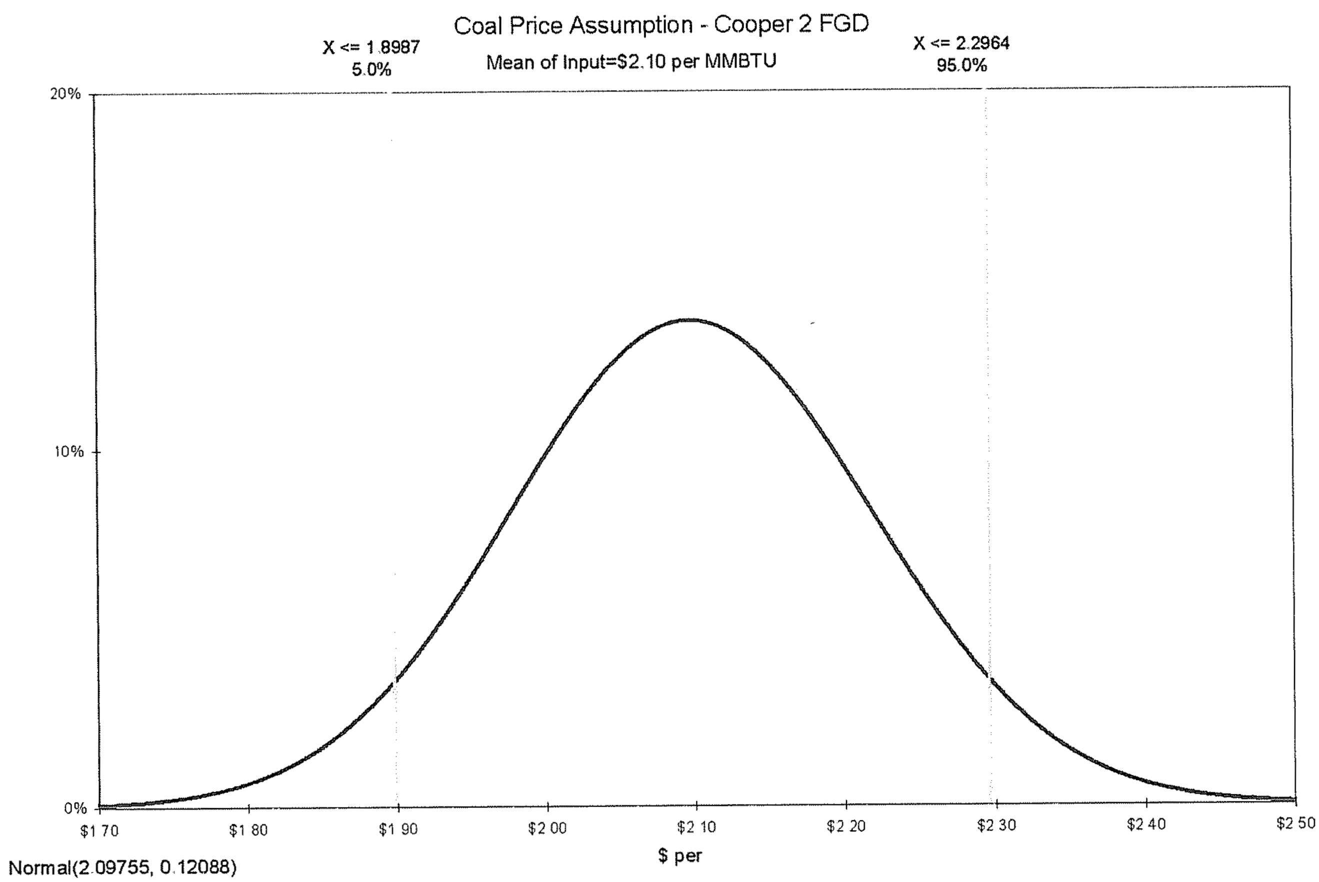

Coal Price Assumption - Cooper 2 CFB
X <= 1.8196
5.0%
Mean of Input=$2.01 per MMBTU
X <= 2.2007
95.0%
20%
10%
0%
$1 60
$1 70
$1 80
$1 90
$2 00
$2 10
$2 20
$2 30
$2 40
Normal(2.01015, 0.11583)
$ per MMBTU


Coal Price Assumption - Dale CFB
X <= 1.9303
5.0%
Mean of Input=$2.14 per MMBTU
X <= 2.3570
95.0%
20%
10%
0%
$1 70
$1 80
$1 90
$2 00
$2 10
$2 20
$2 30
$2 40
$2 50
$2 60
Lognorm(7.3734, 0.12973) Shift=-5.2317
$ per MMBTU


Coal Price Assumption - Dale 1, 2, 3, 4 PC
X <= 2.340
5.0%
Mean of Input=$2.60 per MMBTU
X <= 2.858
95.0%
20%
10%
0%
$2.10
$2.20
$2.30
$2.40
$2.50
$2.60
$2.70
$2.80
$2.90
$3.00
$3.10
$3.20
Normal(2.59917, 0.15749)
$ per MMBTU


Coal Price Assumption - Spurlock 1 and 2 PC
X <= 1.8942
5.0%
Mean of Input=$2.06 per MMBTU
X <= 2.2259
95.0%
20%
10%
0%
$1.70
$1.80
$1.90
$2.00
$2.10
$2.20
$2.30
$2.40
$2.50
Normal(2.06007, 0.10081)
$ per MMBTU

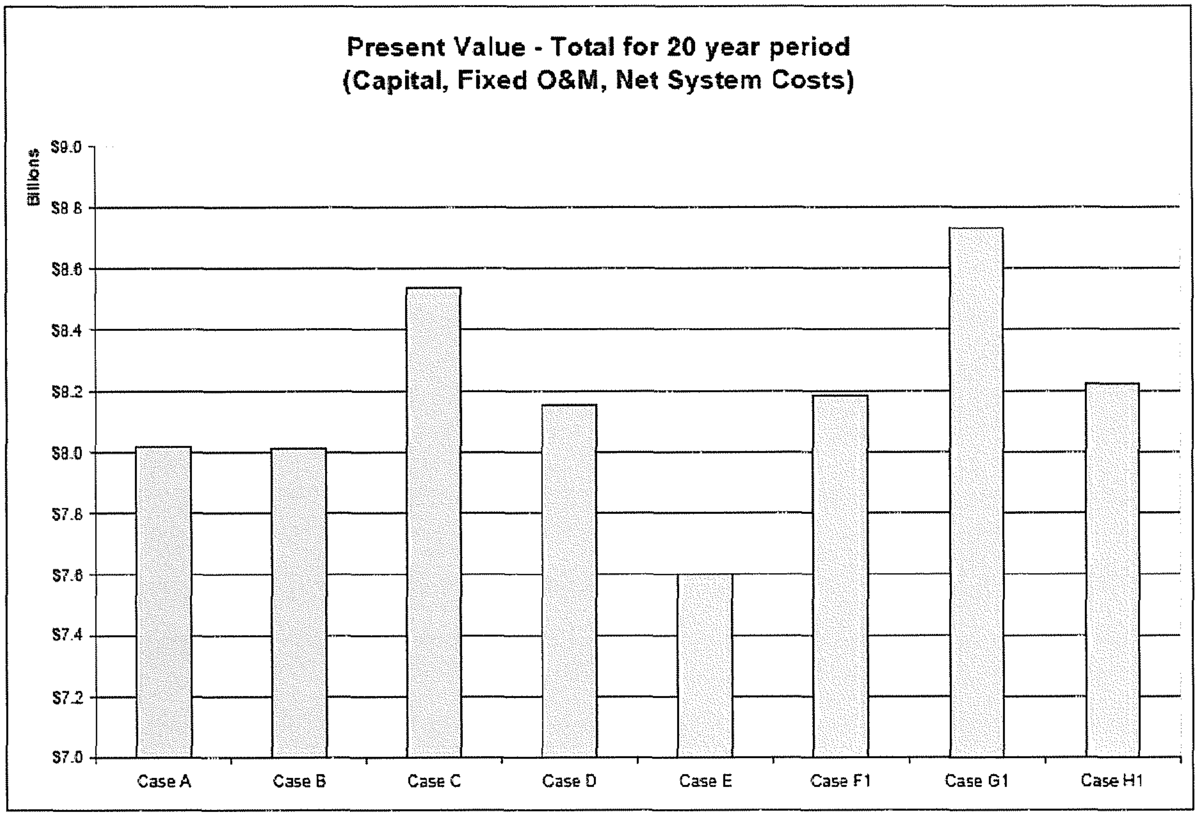

Coal Price Assumption - Cooper CAPP 2.2
X <= 2.1073
5.0%
Mean of Input=$2.33 per MMBTU
X <= 2.5486
95.0%
20%
10%
0%
$1.90
$2.00
$2.10
$2.20
$2.30
$2.40
$2.50
$2.60
$2.70
$2.80
Normal(2.32794, 0.13415)
$ per MMBTU

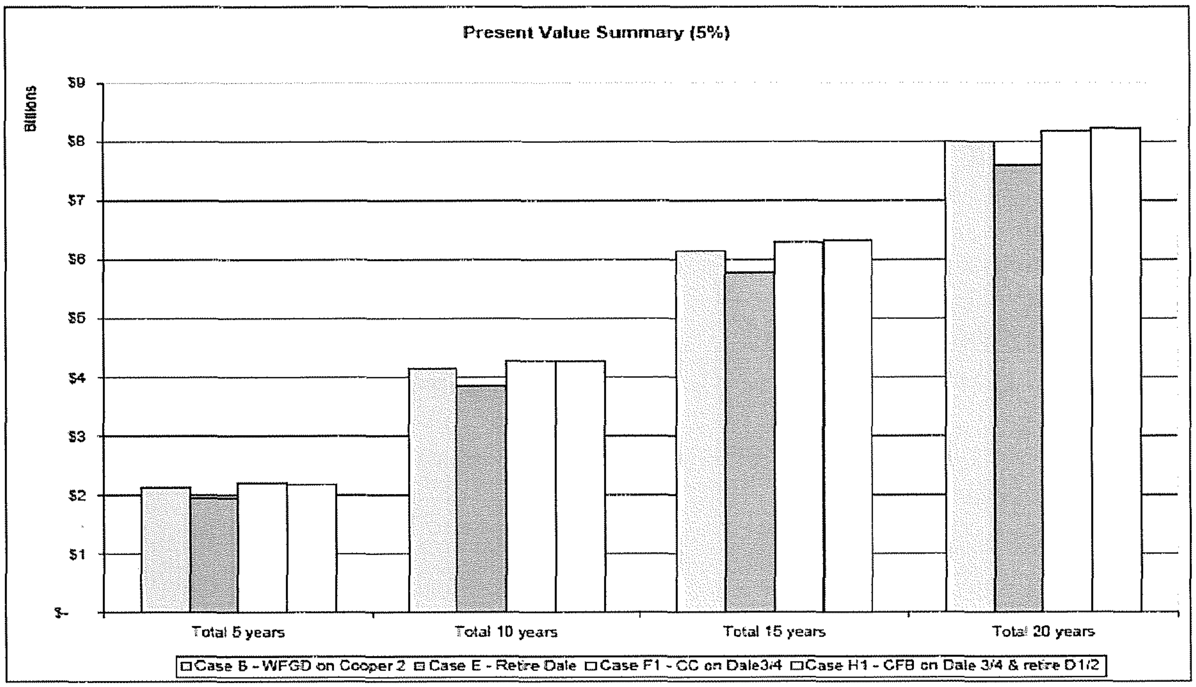

Coal Price Assumption - Cooper 2 FGD
X <= 1.8987
5.0%
Mean of Input=$2.10 per MMBTU
X <= 2.2964
95.0%
20%
10%
0%
$1.70
$1.80
$1.90
$2.00
$2.10
$2.20
$2.30
$2.40
$2.50
$ per
Normal(2.09755, 0.12088)

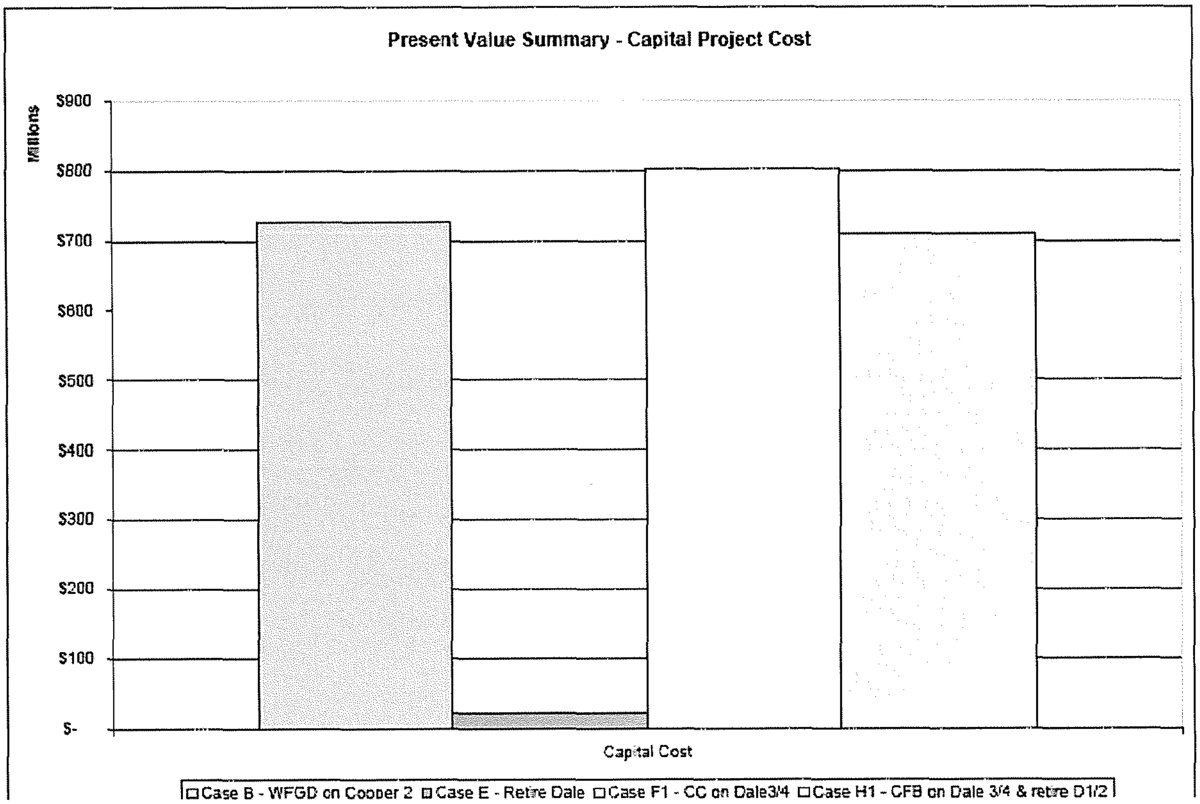
Range of 2012 Emission Prices			
	High	**Mid**	**Low**
SO2 (Ton)	$1,400	$900	$400
NOX (ton)	$1,565	$1,328	$863
Mercury (lb)	$41,293	$33,034	$29,731
Ozone (Ton)	$983	$483	$386
CO_2 starts in 2015 at $4/ton and escalates to $6/ton by 2031.			

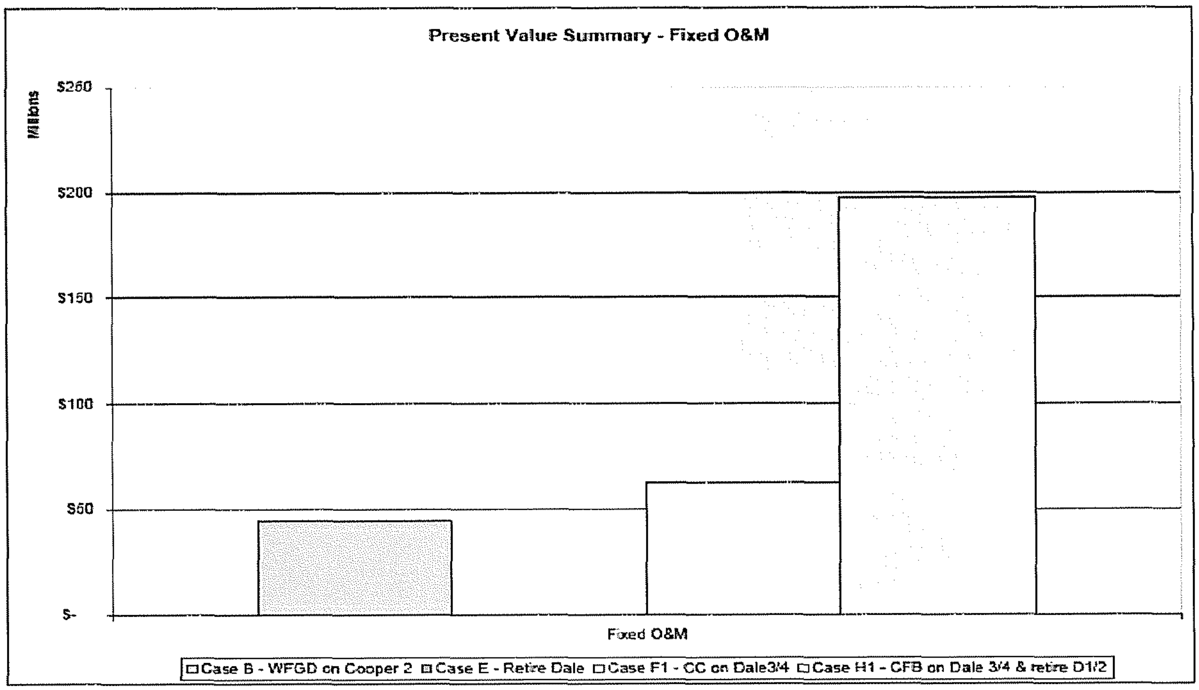
5.0 Results

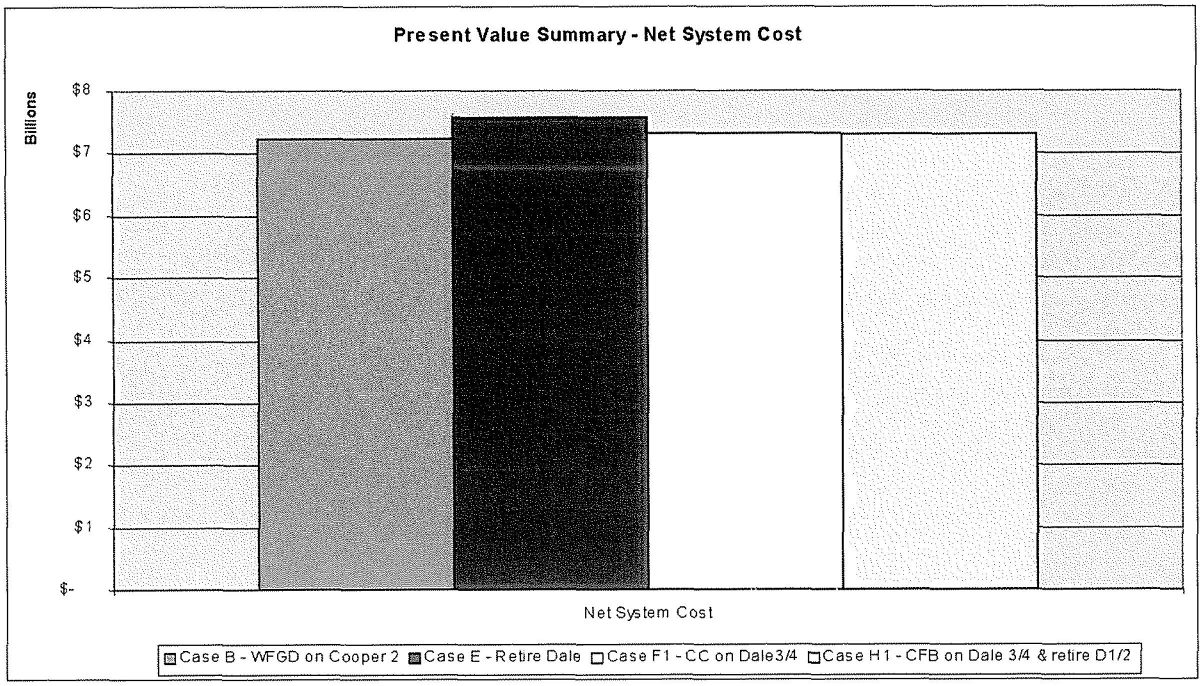
The following charts represent the results of EKPC's initial analysis of the eight alternatives considered.

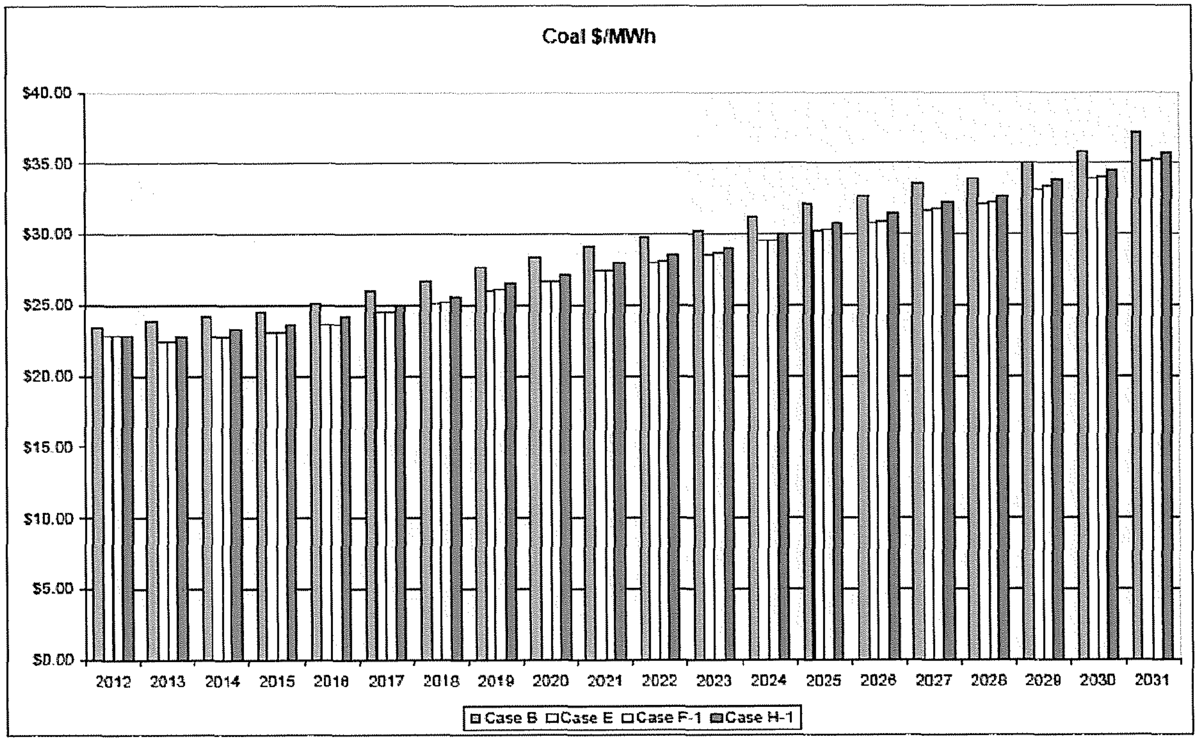

Present Value - Total for 20 year period
(Capital, Fixed O&M, Net System Costs)
Billions
$9.0
$8.8
$8.6
$8.4
$8.2
$8.0
$7.8
$7.6
$7.4
$7.2
$7.0
Case A
Case B
Case C
Case D
Case E
Case F1
Case G1
Case H1

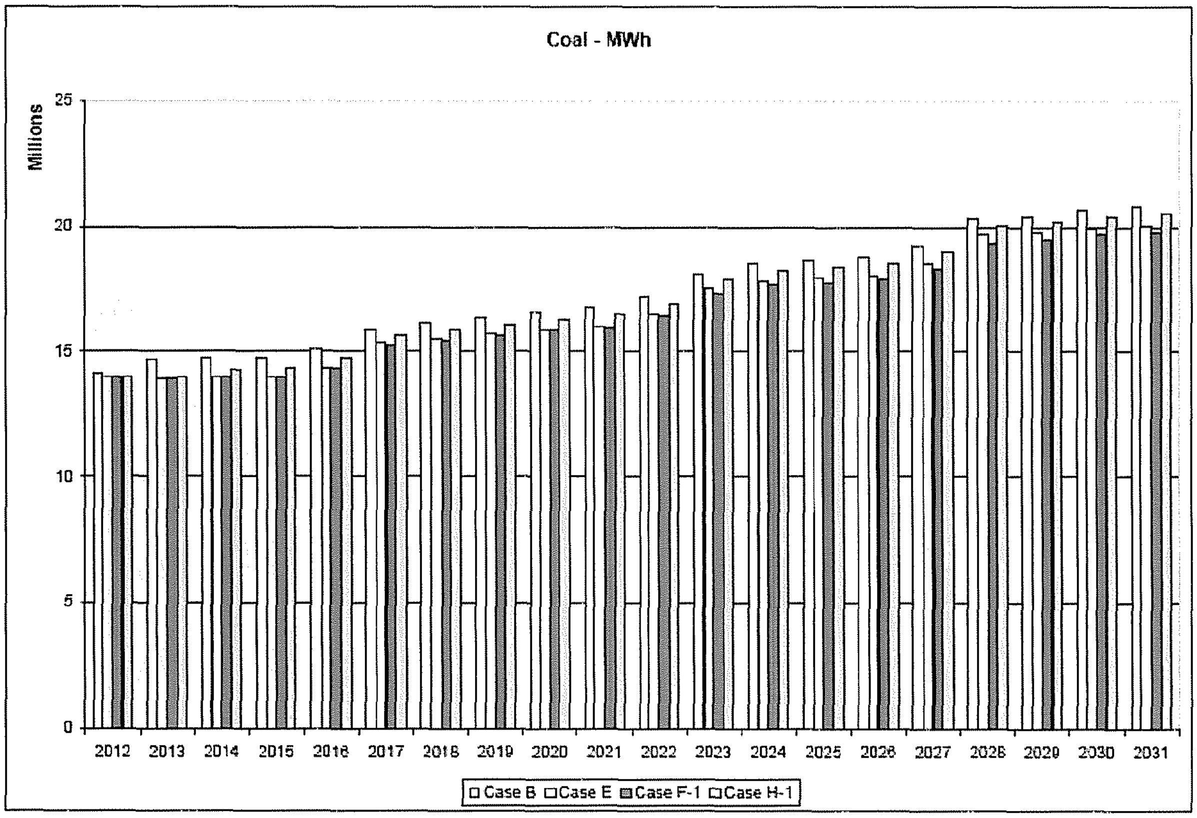

Present Value Summary (5%)
Billions
$9
$8
$7
$6
$5
$4
$3
$2
$1
$-
Total 5 years
Total 10 years
Total 15 years
Total 20 years
Case B - WFGD on Cooper 2
Case E - Retire Dale
Case F1 - CC on Dale3/4
Case H1 - CFB on Dale 3/4 & retire D1/2


Present Value Summary - Capital Project Cost
Millions
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
Capital Cost
Case B - WFGD on Cooper 2
Case E - Retire Dale
Case F1 - CC on Dale3/4
Case H1 - CFB on Dale 3/4 & retire D1/2

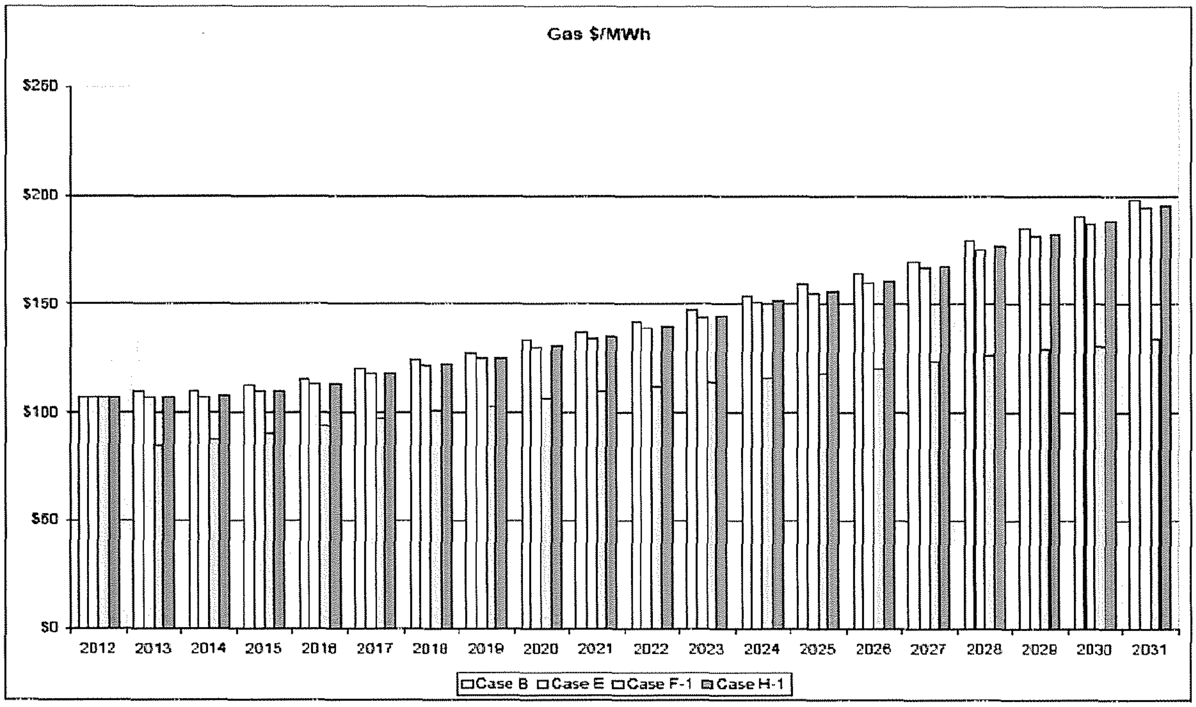

Present Value Summary - Fixed O&M
Millions
$250
$200
$150
$100
$50
$-
Fixed O&M
Case B - WFGD on Cooper 2
Case E - Retire Dale
Case F1 - CC on Dale3/4
Case H1 - CFB on Dale 3/4 & retire D1/2


Present Value Summary - Net System Cost
Billions
$8
$7
$6
$5
$4
$3
$2
$1
$-
Net System Cost
Case B - WFGD on Cooper 2
Case E - Retire Dale
Case F1 - CC on Dale3/4
Case H1 - CFB on Dale 3/4 & retire D1/2

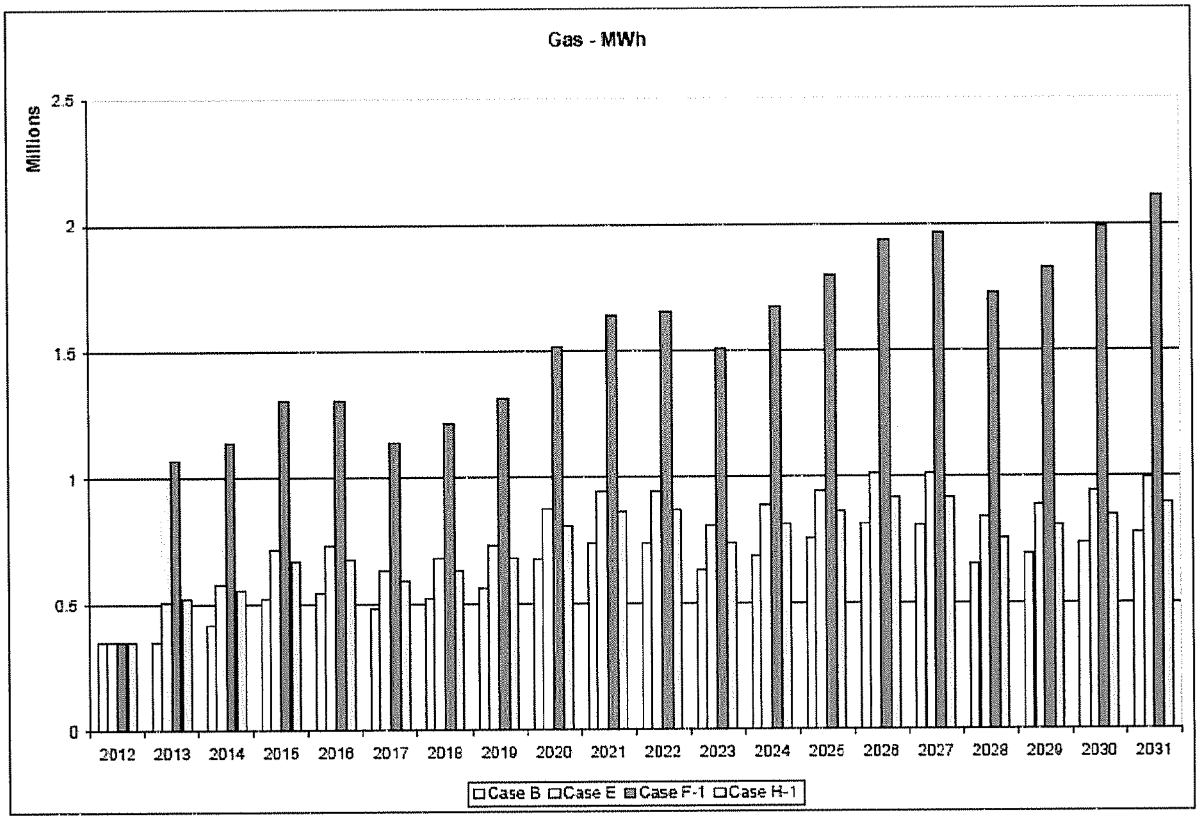

Coal $/MWh
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Case B
Case E
Case F-1
Case H-1

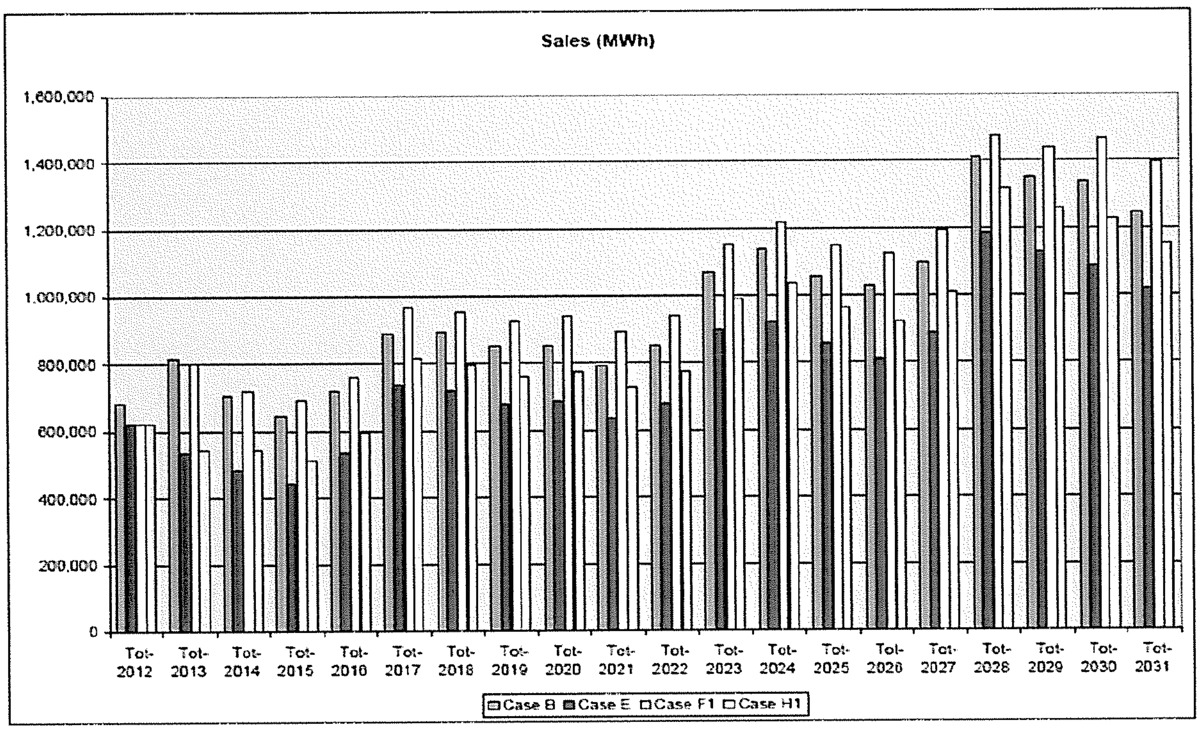


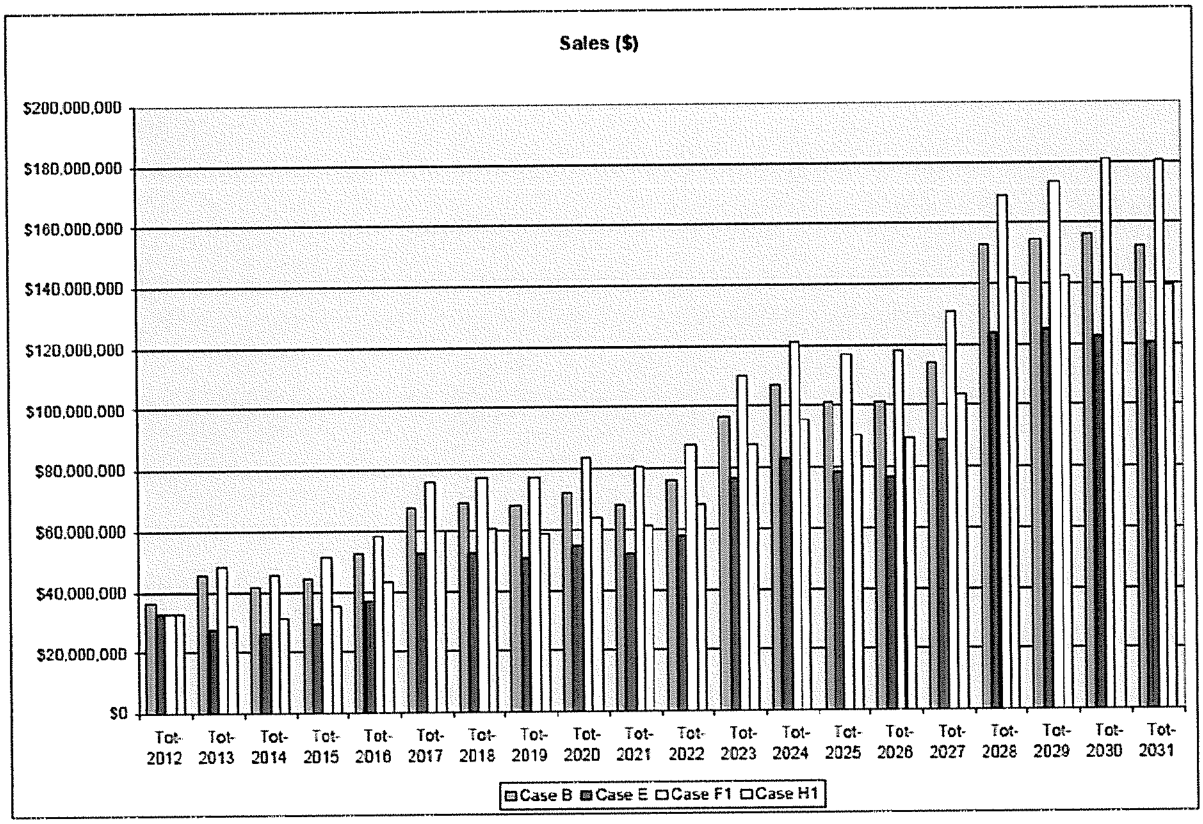
Coal - MWh
Millions
25
20
15
10
5
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Case B Case E Case F-1 Case H-1

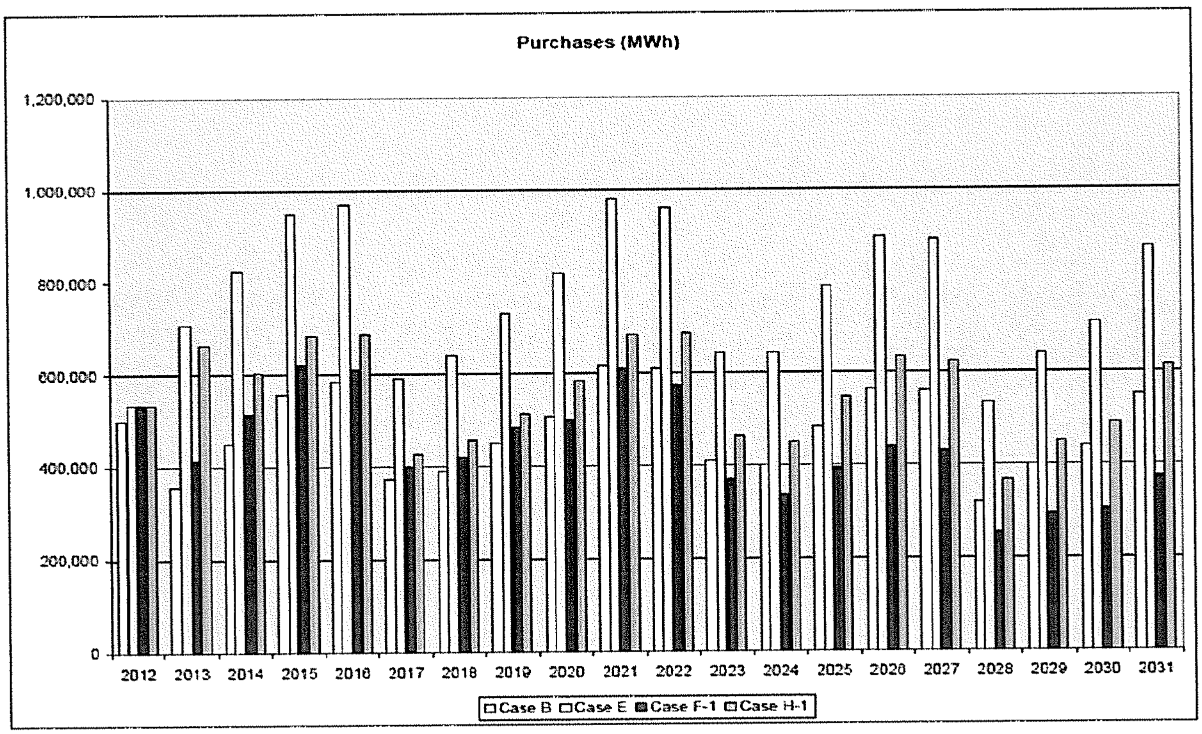


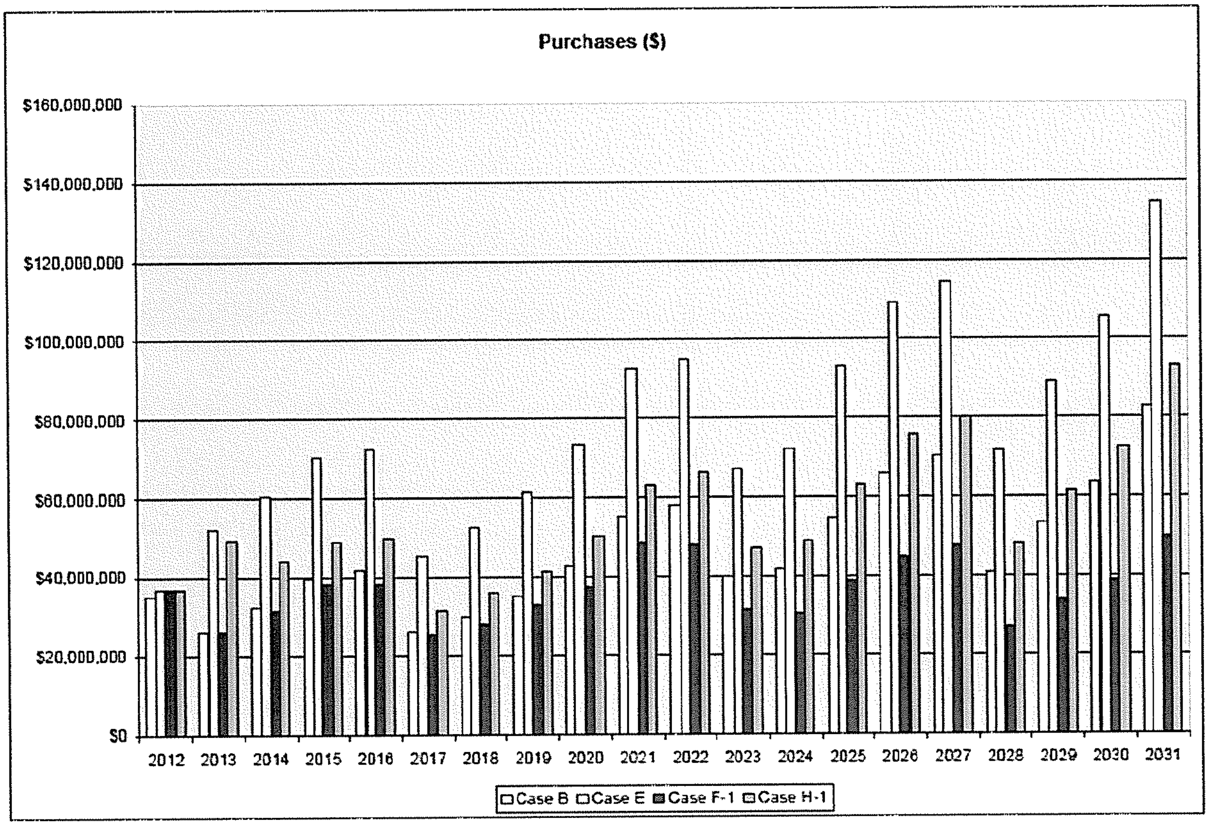
Gas $/MWh
$250
$200
$150
$100
$50
$0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Case B Case E Case F-1 Case H-1

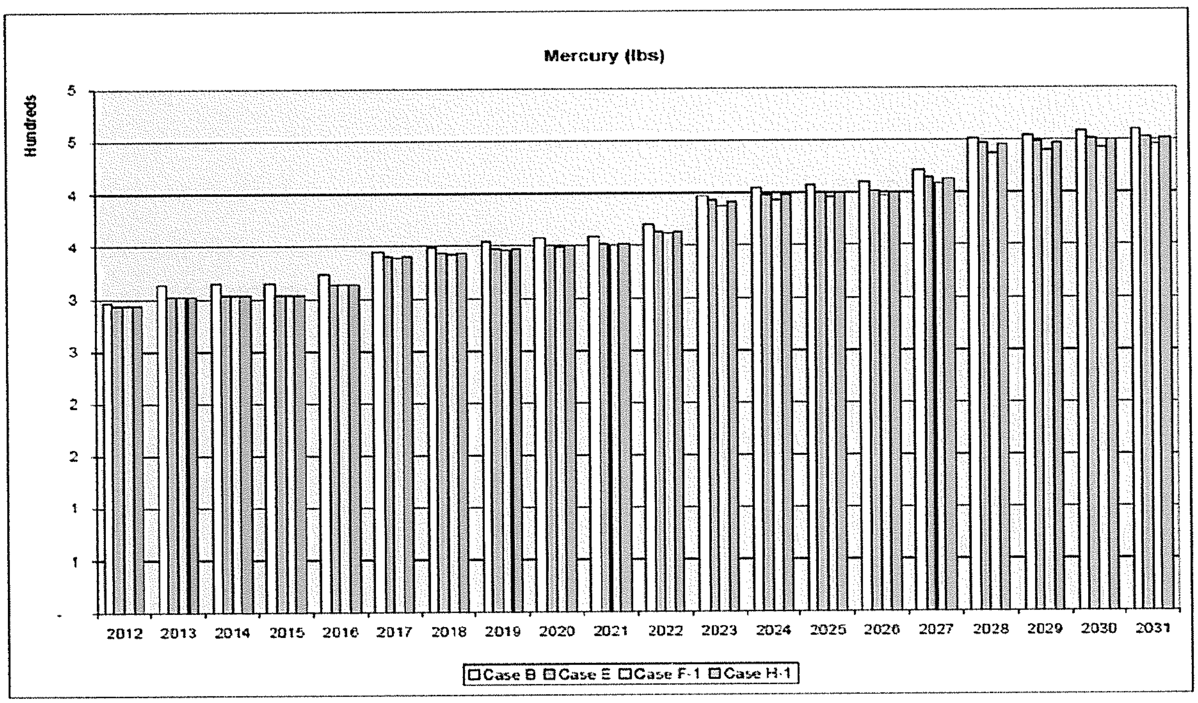

Gas - MWh
Millions
2.5
2
1.5
1
0.5
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Case B Case E Case F-1 Case H-1

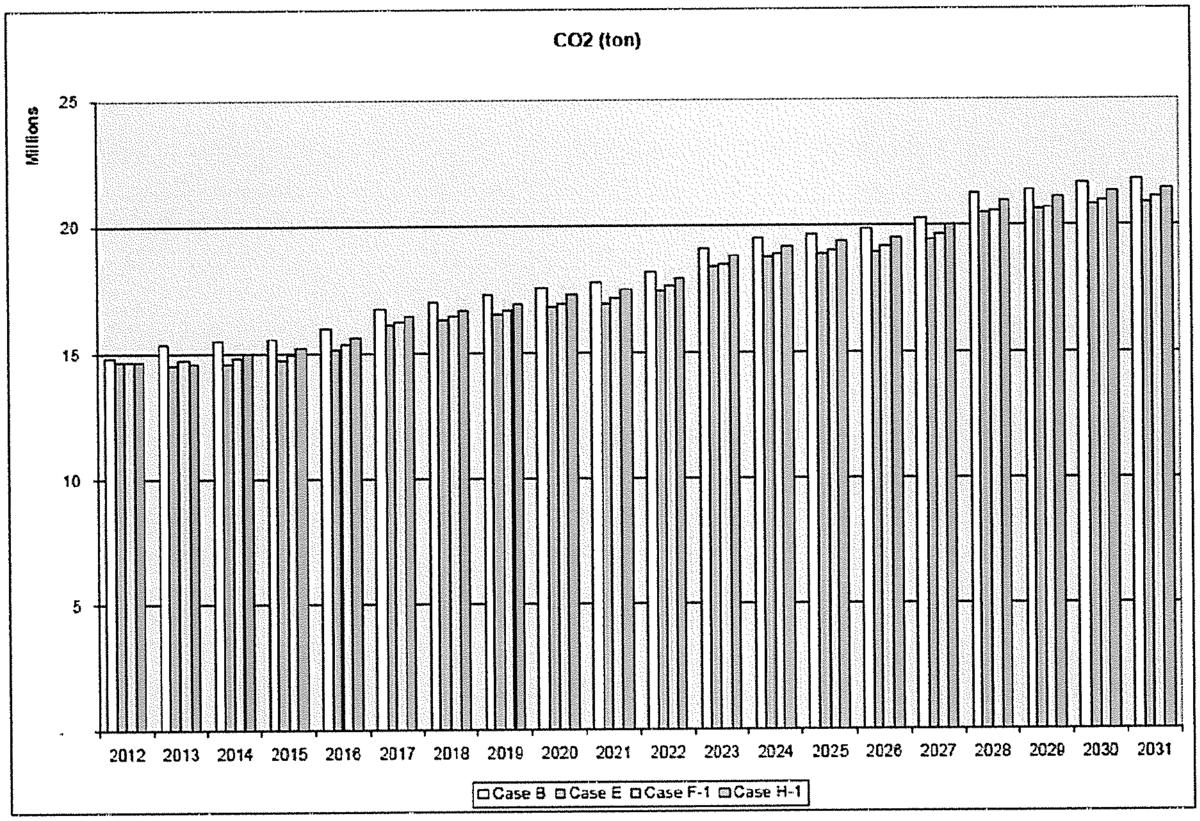

Sales (MWh)
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Tot-2012 Tot-2013 Tot-2014 Tot-2015 Tot-2016 Tot-2017 Tot-2018 Tot-2019 Tot-2020 Tot-2021 Tot-2022 Tot-2023 Tot-2024 Tot-2025 Tot-2026 Tot-2027 Tot-2028 Tot-2029 Tot-2030 Tot-2031
Case B Case E Case F1 Case H1

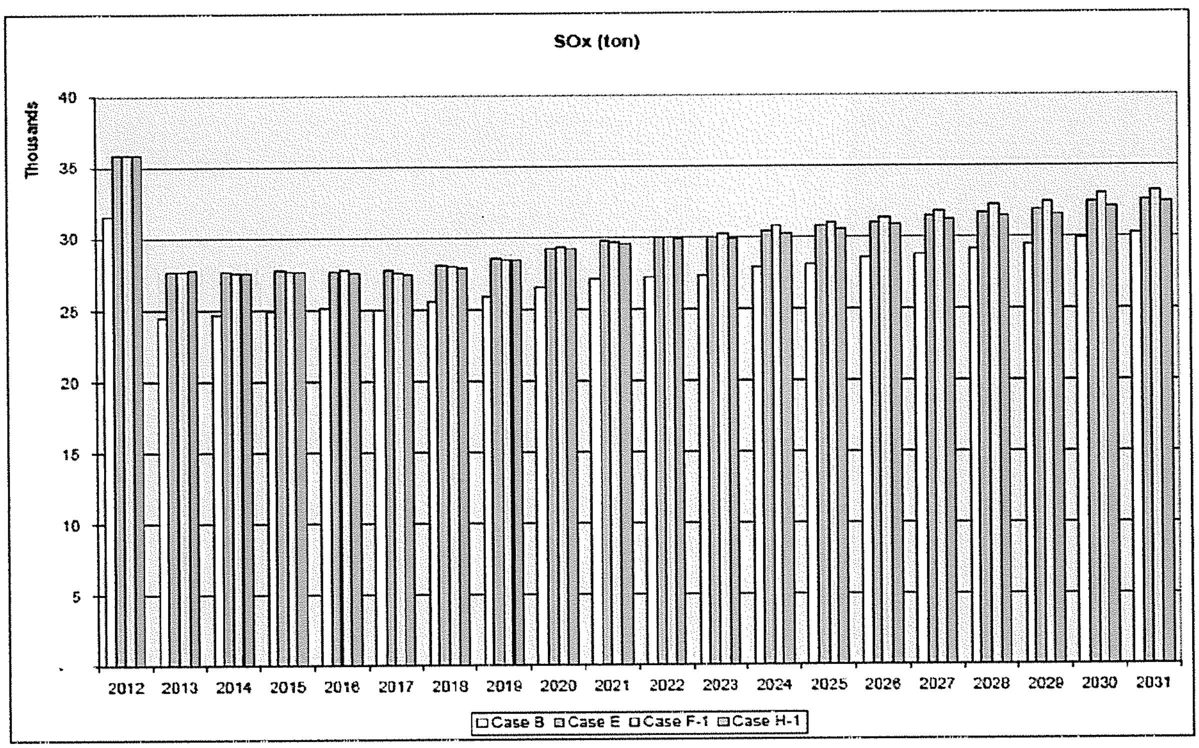

Sales ($)
$200,000,000
$180,000,000
$160,000,000
$140,000,000
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$0
Tot-2012
Tot-2013
Tot-2014
Tot-2015
Tot-2016
Tot-2017
Tot-2018
Tot-2019
Tot-2020
Tot-2021
Tot-2022
Tot-2023
Tot-2024
Tot-2025
Tot-2026
Tot-2027
Tot-2028
Tot-2029
Tot-2030
Tot-2031
Case B
Case E
Case F1
Case H1

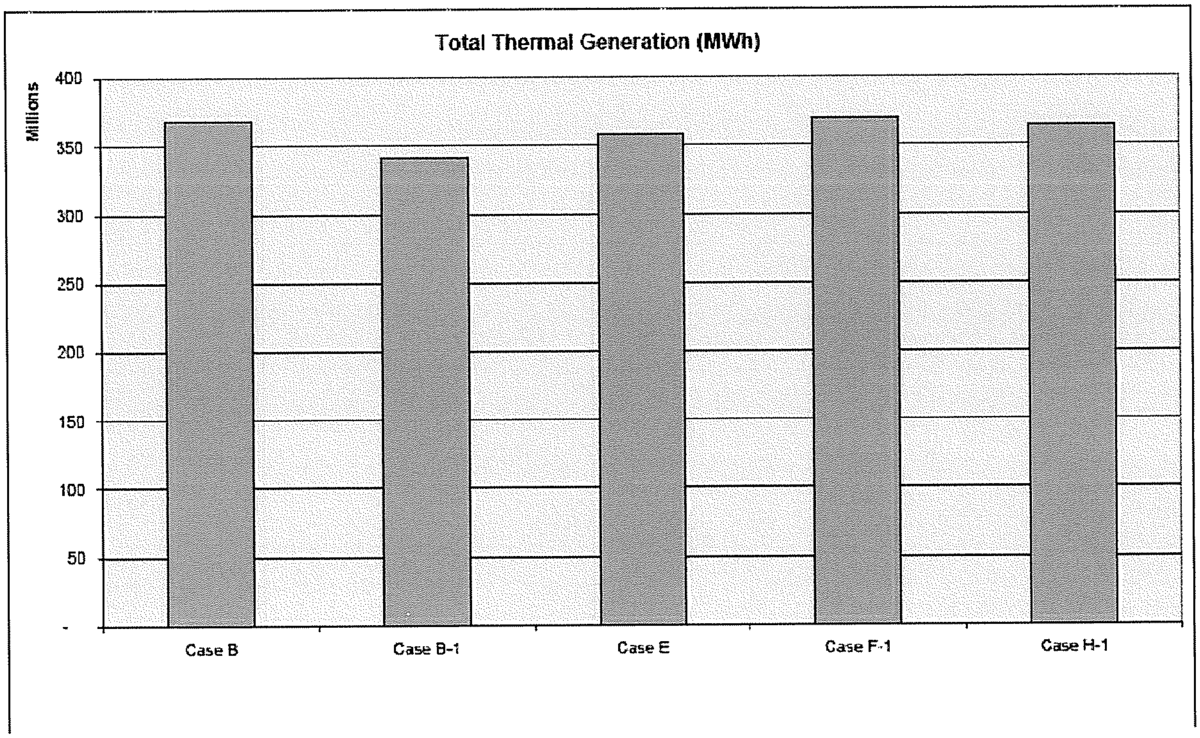

Purchases (MWh)
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Case B
Case E
Case F-1
Case H-1

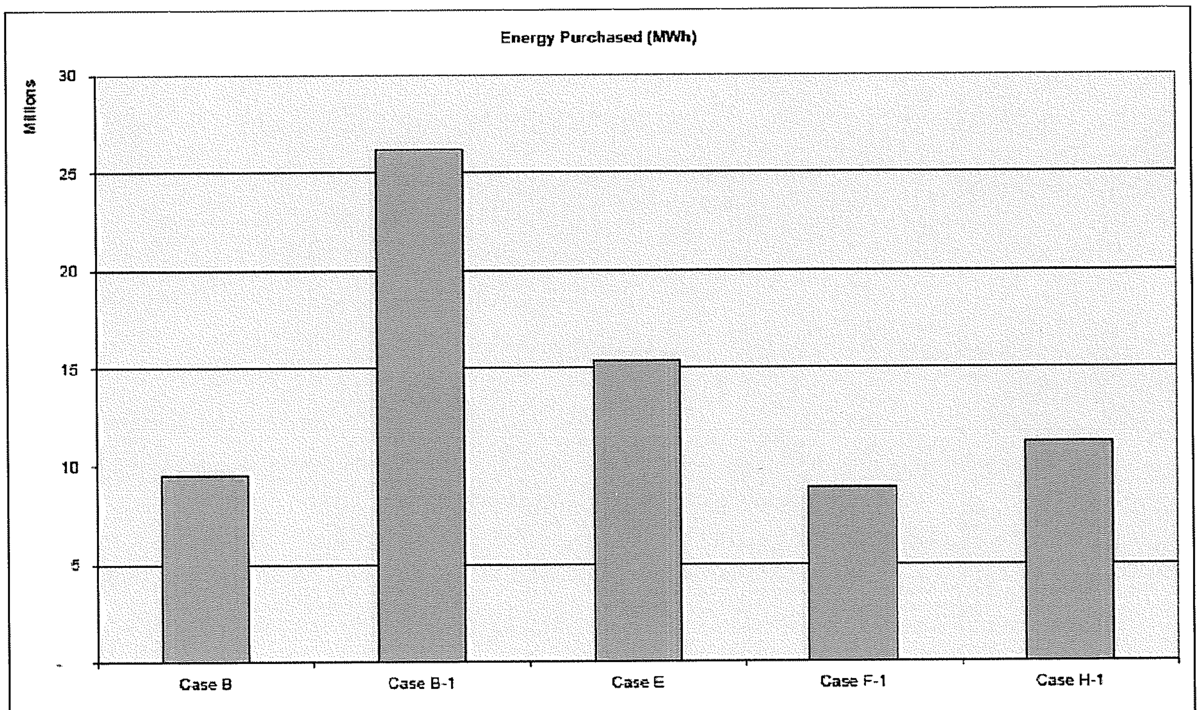

Purchases ($)
$160,000,000
$140,000,000
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Case B Case E Case F-1 Case H-1


Mercury (lbs)
Hundreds
5
5
4
4
3
3
2
2
1
1
-
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Case B Case E Case F-1 Case H-1

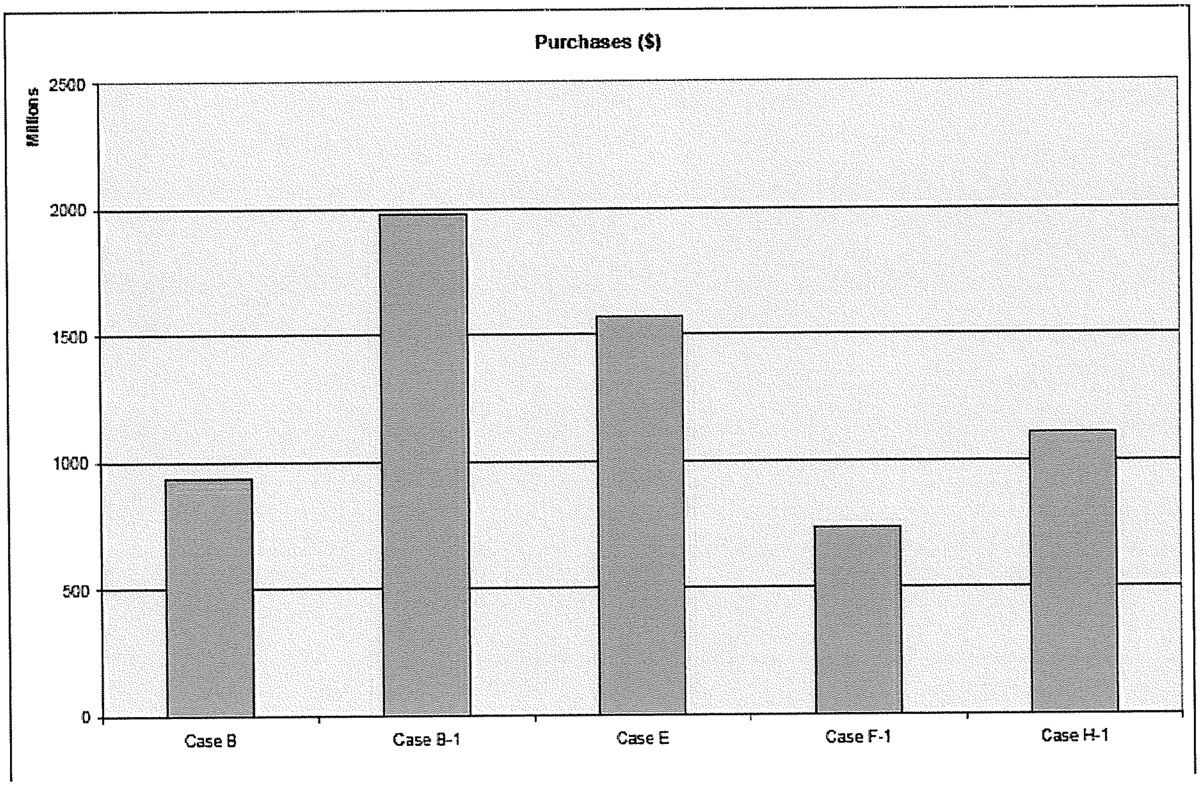

CO2 (ton)
Millions
25
20
15
10
5
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Case B
Case E
Case F-1
Case H-1

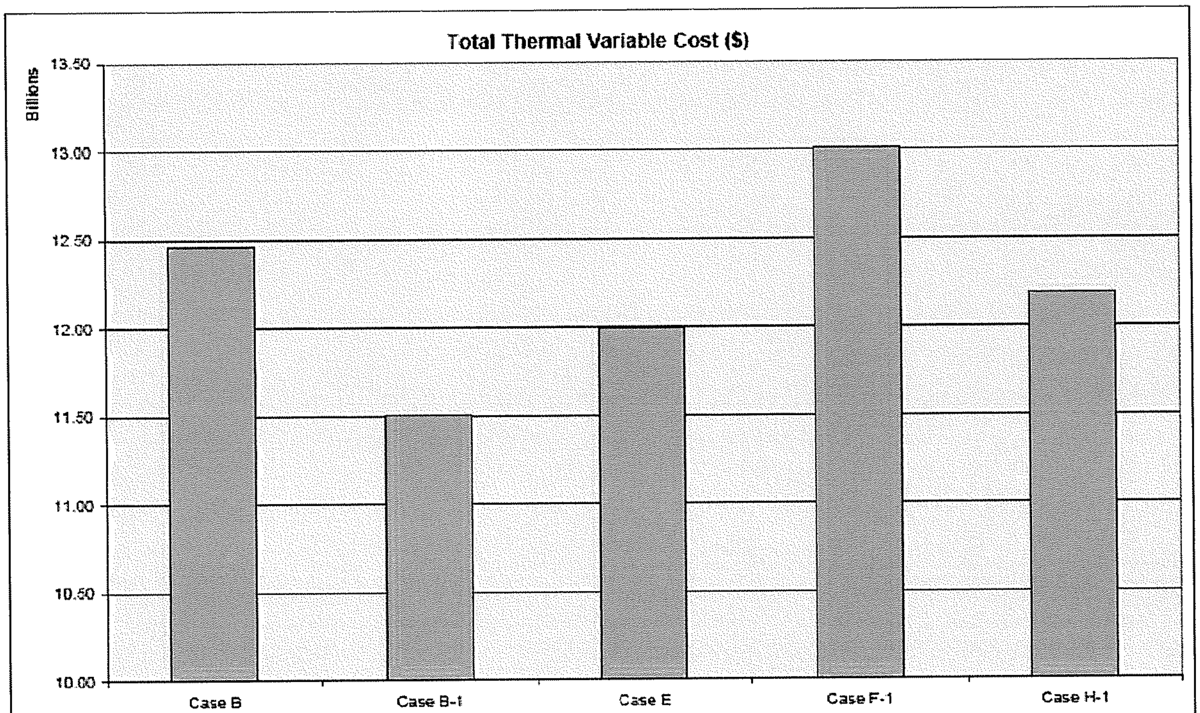

SOx (ton)
Thousands
40
35
30
25
20
15
10
5
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Case B
Case E
Case F-1
Case H-1



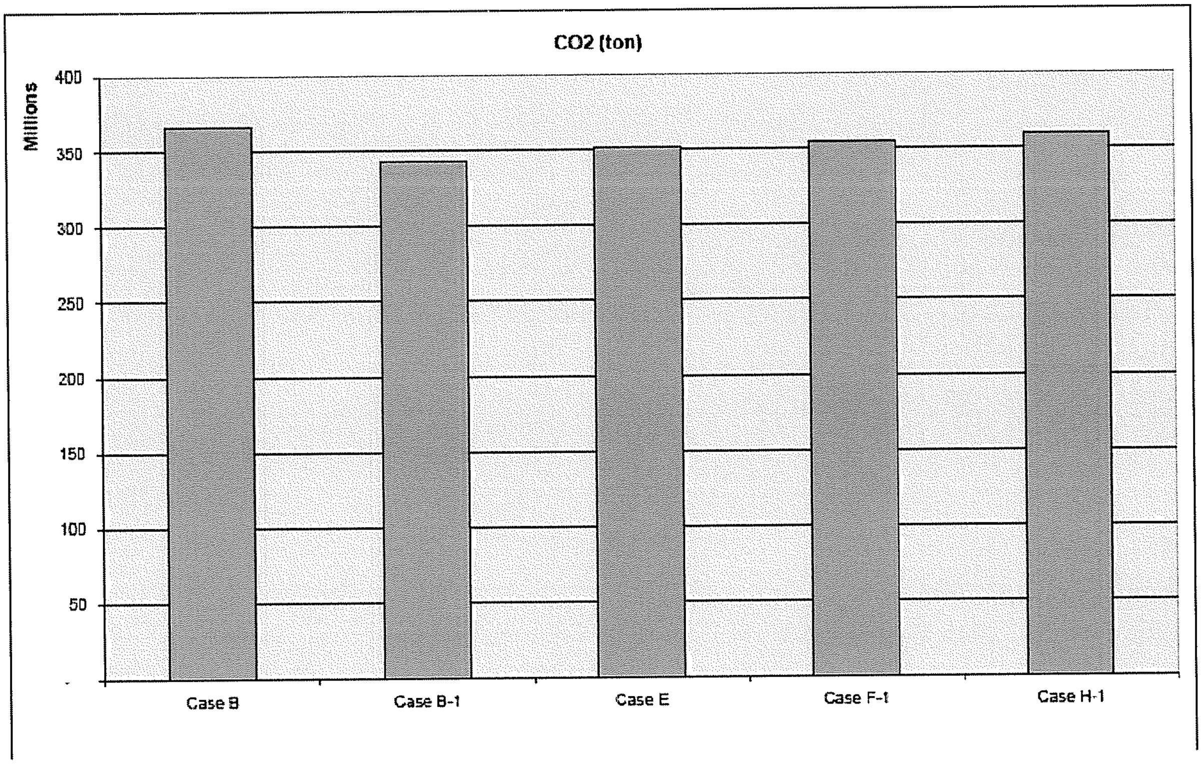


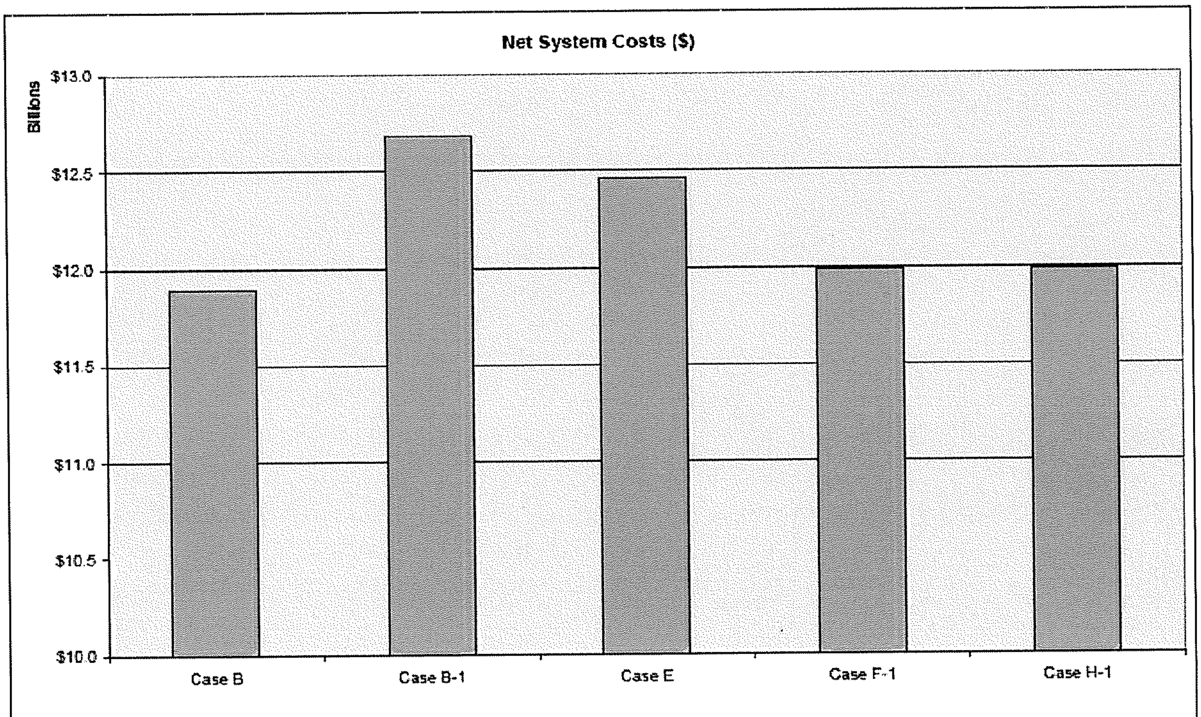
[Case B-1: $30/ton CO2 Starting 2015]





[Case B-1: $30/ton CO2 Starting 2015]



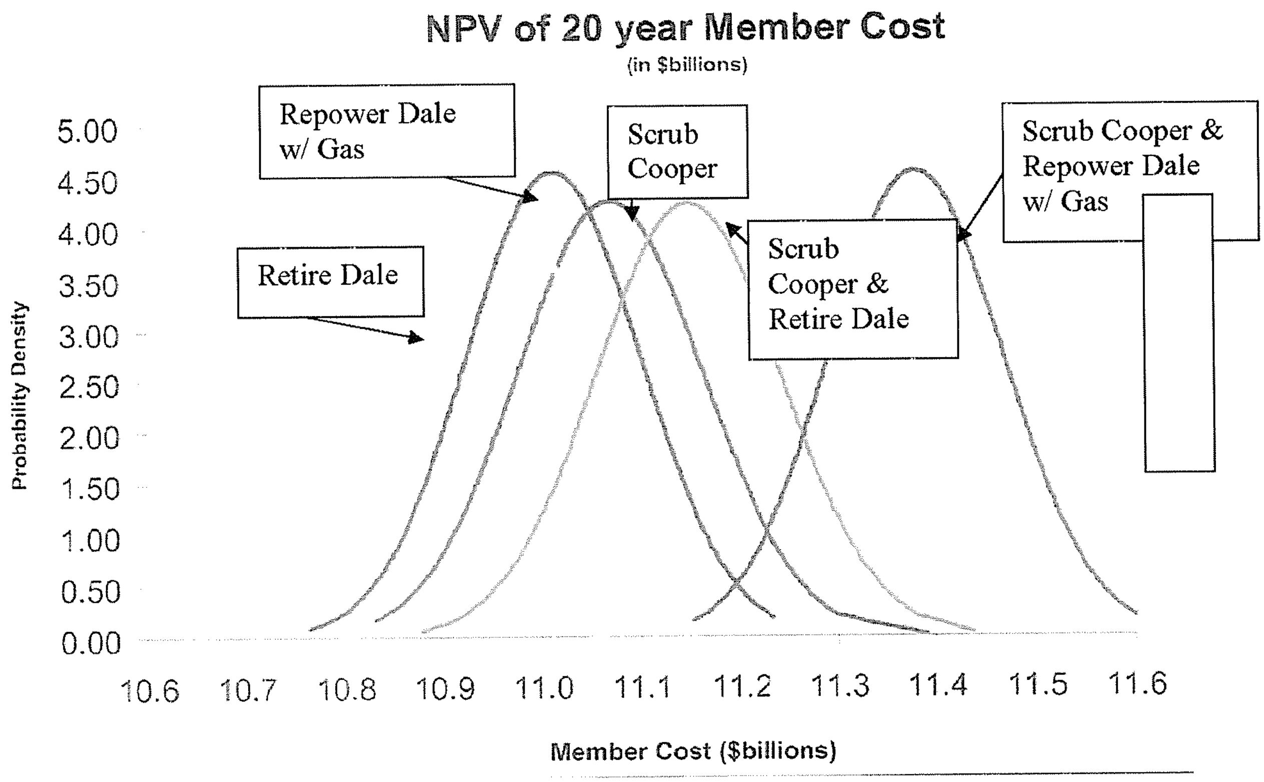


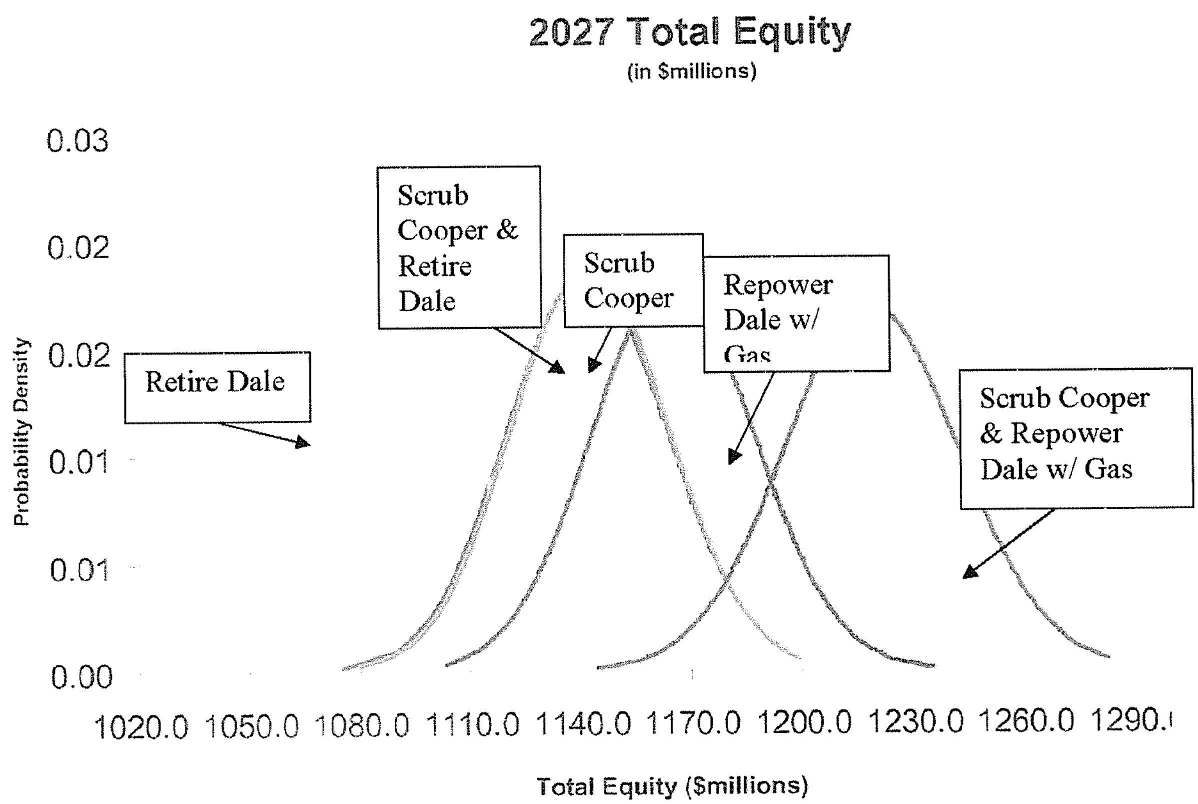
[Case B-1: $30/ton CO2 Starting 2015]

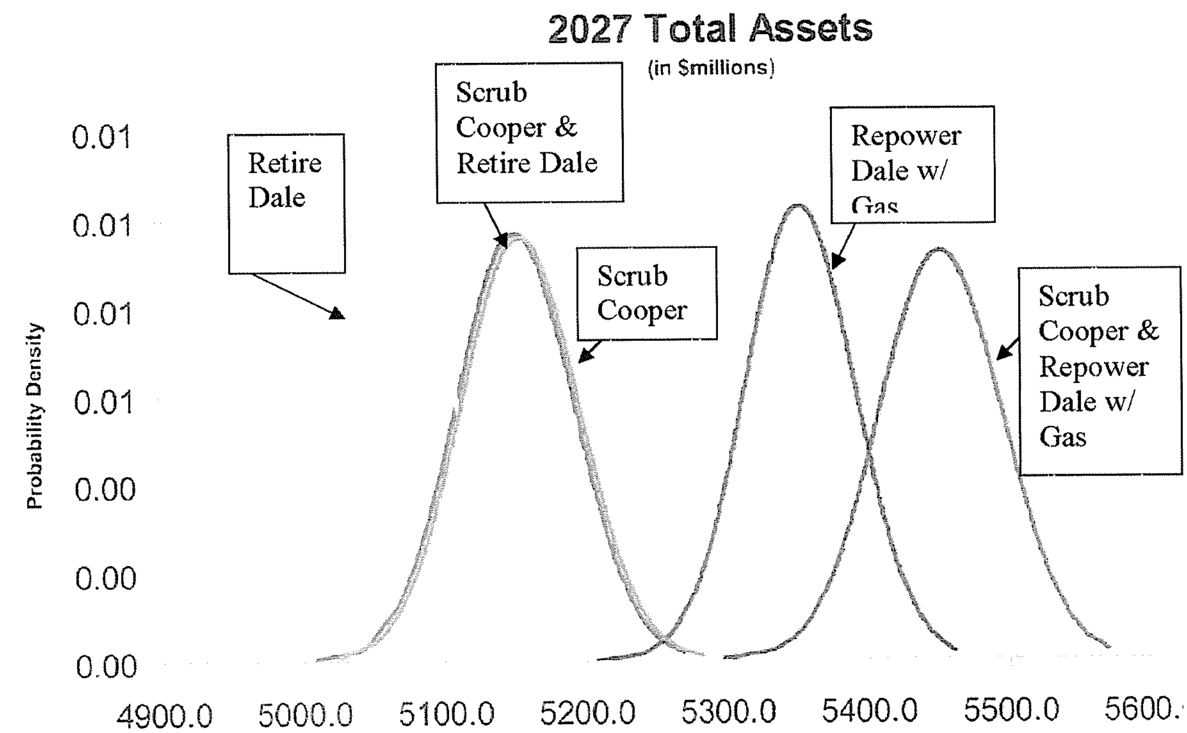
Based on these results, EKPC determined that the best four alternatives were:

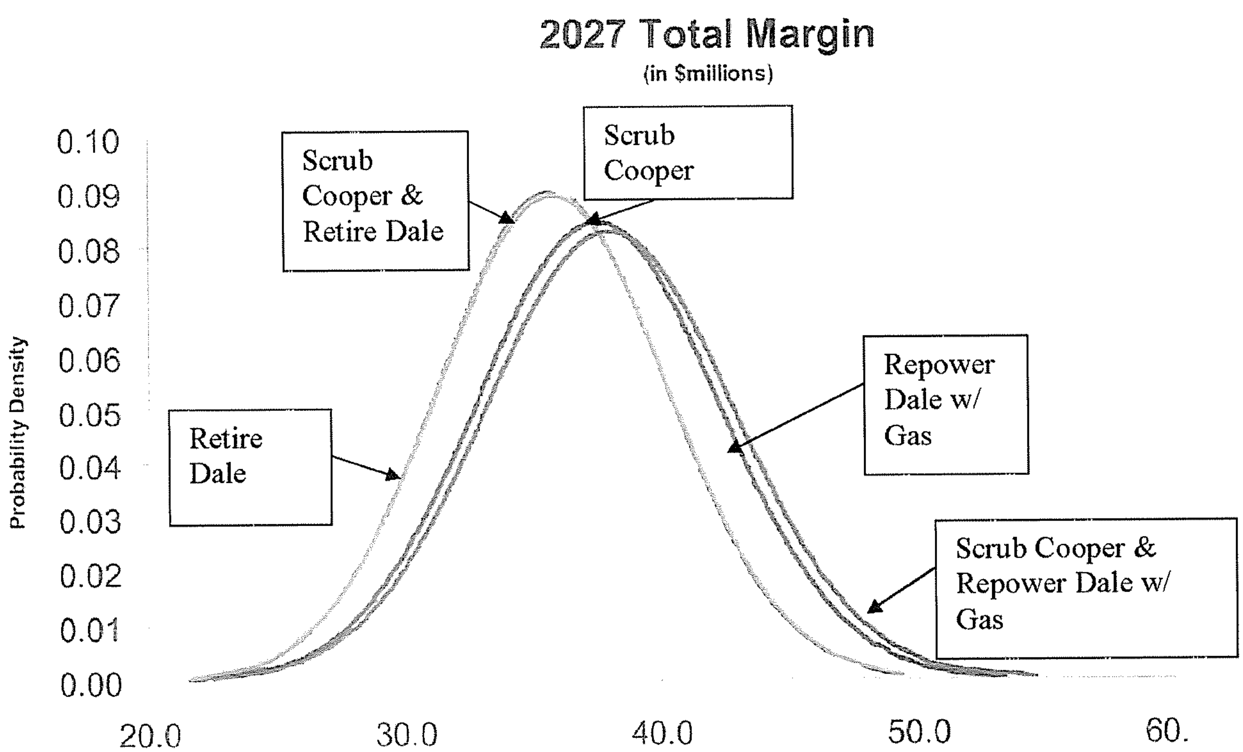
- Scrub Cooper 2 and keep Dale running
- Retire Dale 1-4 and Purchase Baseload Power Off-System
- Retire Dale 1-4 and Repower w/ Combined Cycle units that use the existing steam turbines
- Retire Dale 1-4 and Repower with a CFB unit

Further refinement and analysis resulted in the following.


NPV of 20 year Member Cost
(in $billions)
Repower Dale w/ Gas
Scrub Cooper
Scrub Cooper & Repower Dale w/ Gas
Retire Dale
Scrub Cooper & Retire Dale
Probability Density
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
10.6 10.7 10.8 10.9 11.0 11.1 11.2 11.3 11.4 11.5 11.6
Member Cost ($billions)


2027 Total Equity
(in $millions)
Scrub Cooper & Retire Dale
Scrub Cooper
Repower Dale w/ Gas
Retire Dale
Scrub Cooper & Repower Dale w/ Gas
Probability Density
0.03
0.02
0.02
0.01
0.01
0.00
1020.0 1050.0 1080.0 1110.0 1140.0 1170.0 1200.0 1230.0 1260.0 1290.
Total Equity ($millions)


2027 Total Assets
(in $millions)
Probability Density
Retire Dale
Scrub Cooper & Retire Dale
Scrub Cooper
Repower Dale w/ Gas
Scrub Cooper & Repower Dale w/ Gas
0.01
0.01
0.01
0.01
0.00
0.00
0.00
4900.0
5000.0
5100.0
5200.0
5300.0
5400.0
5500.0
5600.


2027 Total Margin
(in $millions)
Probability Density
Scrub Cooper & Retire Dale
Scrub Cooper
Retire Dale
Repower Dale w/ Gas
Scrub Cooper & Repower Dale w/ Gas
0.10
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
20.0
30.0
40.0
50.0
60.

As demonstrated with the previous financial analysis, the alternatives were extremely close together and no obvious one was a clear winner or loser. The total 20 year NPV for Case B (Scrub Cooper) was $7.93billion, Case E (Retire Dale) was $$7.60billion, Case F1 (Repower Dale w/ Gas) was $8.18billion and Case H1 (Repower Dale w/ CFB) was $8.26 billion. There is less than 10% difference in the total 20 year NPV cost between the two most extreme cases. The next step was to consider operational concerns that could not be modeled completely.

<u>Operational Concerns</u>
There are various operational concerns with all of the alternatives.

The retirement of Dale Station will create voltage support issues in the Central Kentucky area if no transmission system upgrades are implemented. These issues can be resolved with transmission system upgrades, it is a matter of timing and investment. EKPC is already short on baseload capacity, the retirement of Dale Station would exacerbate that problem. EKPC has yet to retire a baseload unit, so the maintenance of a brownfield site would be new territory. The economic analysis for the retirement of Dale Station is based on the assumption that EKPC will be able to import sufficient baseload power on an economic and reliable basis. EKPC has never depended on this much baseload from an outside resource and there is risk in doing so.

Repowering Dale Station with gas or CFB coal also has operating issues. The availability and price of gas are significant risks associated with this alternative. Maintaining multiple fuels on the limited amount of available land at the Dale site is also a concern with this alternative.

Scrubbing Cooper Station requires a major investment in a 40+ year old plant. There is no reason to think the plant can not be maintained as a viable unit for a lot longer, but it is a risk. The Consent Decree requires that the chosen solution be implemented by the end of 2012. The construction lead time for a scrubber could pose problems in meeting this deadline. Lastly, if the chosen technology is to scrub both units at Cooper Station the reliability of the plant suffers tremendously. Any outage of the scrubber would affect both units, which creates significant voltage and transmission issues in the area. However, adding a scrubber requires less capital investment than repowering Dale Station with gas or CFB.

<u>Power Supply Concerns</u>
EKPC has overall power supply concerns that could be helped or exacerbated by these alternatives.

- Low Reserve Margin – EKPC is short on capacity and is operating with a low reserve margin currently. EKPC's expansion plan is based on the goal of obtaining a 12% reserve margin during the winter peak season within five years. Any of the alternatives that reduce existing capacity just exacerbate this issue.
- EKPC is challenged with meeting its CPS1 operating requirements due to large fluctuations in its load profile within the hour. Coal fired units have trouble

moving quickly enough to follow the load. Alternatives that decrease the amount of capacity available for load following add to this problem. A combined cycle unit could help improve this situation.

- EKPC could be faced with adding a significant amount of renewable power supply to its portfolio if a Renewable Portfolio Standard is enacted in Kentucky. Renewables tend to be non-dispatchable and non-load following. The loss of flexible generation on the system to fill in the gaps for this type of generation could result in operating issues in the future.
- Carbon emissions will most likely be constrained in the near future. There is no legislation currently in place, therefore, there is no definitive plan for remediation. EKPC has attempted to add costs for these constraints in the various alternatives.

Potential Environmental Regulations

At the time the analysis was being conducted, EKPC assumed CAIR and Best Available Retrofit Technology ("BART") were both moving forward as proposed by the EPA. Since that time, CAIR has been vacated but the outcome is still debatable. EKPC is moving forward with the assumption that BART, or something similar, will be a future air quality standard that EKPC will have to meet. Kenvirons, Inc. submitted an assessment of EKPC's alternatives to meet BART to the Kentucky Division for Air Quality on behalf of EKPC on July 24, 2007. That assessment indicated that the application of a WFGD/WESP controls retrofit on Cooper Units 1 and 2, with a filterable PM limit of 0.030 lb/mmBtu, mitigates any adverse visibility impact in Class I areas within 300 km of each source. Therefore, it appears that EKPC will need to scrub Cooper Station in the near future to meet the BART regulations.

6.0 Conclusions

- Based on the economic analysis, retiring Dale Station, repowering Dale Station and scrubbing Cooper Station are all within a reasonable range of expected financial outcomes and no clear choice can be made with just the economic evaluation.

- Operational and power supply concerns are apparent with any of the alternative choices.

- BART or a similar regulation appears to be apparent in the near future and EKPC will be required to scrub Cooper Station to meet those requirements.

Based on these conclusions, EKPC chose to move forward with the alternative to install new environmental control equipment at Cooper Station to meet the requirements of the Consent Decree and future BART regulations.

Report on the

Power Plant Assessment Study

for the

East Kentucky Power Cooperative
Winchester, KY

EAST KENTUCKY POWER COOPERATIVE

Project 46644

December 2007

Burns & McDonnell
SINCE 1898

Power Plant Assessment Study

prepared for

East Kentucky Power Cooperative
Winchester, Kentucky

December 2007

Project 46644

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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1.0 EXECUTIVE SUMMARY

In August 2007 East Kentucky Power Cooperative, Inc. (EKPC) contracted with Burns & McDonnell Engineering Company (Burns & McDonnell) to perform a Power Plant Life Extension Study (Study). One of the main objectives of this Study was to complete a quantitative evaluation of options available to EKPC related to a Consent Decree entered on December 4, 2007. This Consent Decree is the result of a Complaint filed against EKPC by the United States Environmental Protection Agency (EPA) which resulted in restrictions placed on emission rates and monitoring of nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM), and mercury (Hg). In the Consent Decree, the EPA alleges that EKPC failed to obtain the necessary permits and install the controls necessary under the Clean Air Act to reduce its sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that EKPC violated various operating permit conditions. EKPC has denied and continues to deny the violations alleged in the Complaint, but has agreed to the obligations in the Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment.

In the Consent Decree, the EPA has given EKPC the option to either install and continuously operate NO_x and SO_2 emission controls at Cooper Unit 2 or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012. EKPC does have the option of repowering Dale Units 3 and 4 by May 31, 2014. The decision to either install new emission controls at Cooper Unit 2 or retire Dale Units 3 and 4 must be submitted in writing to the EPA no later than December 21, 2009.

Burns & McDonnell in conjunction with EKPC considered a number of different options in meeting the obligations of the Consent Decree. Four options related to the disposition of Cooper Unit 2 and four options related to the disposition of Dale Units 3 and 4 were considered. The features of each option are outlined in table 1-1 below:

Table 1-1

Cases Analyzed to Satisfy Consent Decree

CASE A - COOPER 2 DRY SCRUBBER				NOTES/FEATURES
Cooper 1	Continuous Emissions Monitoring	Dale 1	Operate/Determine retire date/Regular O&M	Separates Cooper 1&2 completely (no common stack)
Cooper 2	SDA	Dale 2	Operate/Determine retire date/Regular O&M	
	Baghouse			
	Stack	Dale 3	Operate/Determine retire date/Regular O&M	
	SCR			
	Booster Fan	Dale 4	Operate/Determine retire date/Regular O&M	

CASE B - COOPER 2 WET SCRUBBER				NOTES/FEATURES
Cooper 1	Continuous Emissions Monitoring	Dale 1	Operate/Determine retire date/Regular O&M	Separates Cooper 1&2 completely (no common stack)
Cooper 2	WFGD	Dale 2	Operate/Determine retire date/Regular O&M	
	ESP Upgrades			
	Stack	Dale 3	Operate/Determine retire date/Regular O&M	
	SCR			
	Booster Fan	Dale 4	Operate/Determine retire date/Regular O&M	

CASE C - COOPER 1&2 - WET SCRUBBERS				NOTES/FEATURES
Cooper 1	Combined Cooper 1 & 2 Wet Scrubber (WFGD)	Dale 1	Operate/Determine retire date/Regular O&M	
	Cooper 1 ESP Upgrades			Dale retirement can be decided in future
	Cooper 1 SCR	Dale 2	Operate/Determine retire date/Regular O&M	Cooper baghouse optional
				Cooper 1&2 become virtually single unit
Cooper2	Combined Cooper 1 & 2 Wet Scrubber (WFGD)	Dale 3	Operate/Determine retire date/Regular O&M	Cooper Site transmission capability study required
	Cooper 2 ESP Upgrades			
	Cooper Stack (2 Liners/1 Shell)	Dale 4	Operate/Determine retire date/Regular O&M	
	Cooper 2 SCR			

CASE D - COOPER 1&2 - REPOWER WITH CFB				NOTES/FEATURES
Cooper 1	Combined Cooper 1 & 2 Wet Scrubber (WFGD)	Dale 1	Operate/Determine retire date/Regular O&M	
	Cooper 1 ESP Upgrades			Dale retirement can be decided in future
	Cooper 1 SCR	Dale 2	Operate/Determine retire date/Regular O&M	Cooper Site transmission capability study required
Cooper2	Combined Cooper 1 & 2 Wet Scrubber (WFGD)	Dale 3	Operate/Determine retire date/Regular O&M	
	Cooper 2 ESP Upgrades			
	Cooper Stack (2 Liners/1 Shell)	Dale 4	Operate/Determine retire date/Regular O&M	
	Cooper 2 SCR			

CASE E - RETIRE DALE 1-4				NOTES/FEATURES
Cooper 1	Continous emmissions monitoring	Dale 1	Shut down 12/31/2012	
	Continue to operate unit			
	No major capital programs	Dale 2	Shut down 12/31/2012	
Cooper 2	Continous emmissions monitoring	Dale 3	Shut down 12/31/2012	
	Continue to operate unit			
	No major capital programs	Dale 4	Shut down 12/31/2012	

CASE F - REPOWER DALE 3&4 WITH COMBINED CYCLE (2-1x1 7FA)				NOTES/FEATURES
Cooper 1	Continous emmissions monitoring	Dale 1	Operate until next major overhaul - then retire	Dale 1&2 retirement can be decided in future
	Continue to operate unit		Regular O&M	Dale Site transmission capability study required
	No major capital programs			
		Dale 2	Operate until next major overhaul - then retire	
Cooper 2	Continous emmissions monitoring		Regular O&M	
	Continue to operate unit			
	No major capital programs	Dale 3	Re-Power with Combined Cycle 5/31/2014	
			Utilize existing Steam Turbine	
		Dale 4	Re-Power with Combined Cycle 5/31/2014	
			Utilize existing Steam Turbine	

CASE G - REPOWER DALE 3&4 WITH COMBINED CYCLE (2-1x1 7EA)				NOTES/FEATURES
Cooper 1	Continous emmissions monitoring	Dale 1	Operate until next major overhaul - then retire	Dale 1&2 retirement can be decided in future
	Continue to operate unit		Regular O&M	Dale Site transmission capability study required
	No major capital programs			
		Dale 2	Operate until next major overhaul - then retire	
Cooper 2	Continous emmissions monitoring		Regular O&M	
	Continue to operate unit			
	No major capital programs	Dale 3	Re-Power with Combined Cycle 5/31/2014	
			Utilize existing Steam Turbine	
		Dale 4	Re-Power with Combined Cycle 5/31/2014	
			Utilize existing Steam Turbine	

CASE H - REPOWER DALE 3&4 WITH CFB				NOTES/FEATURES
Cooper 1	Continous emmissions monitoring	Dale 1	Operate/Determine retire date/Regular O&M	Dale 1&2 retirement can be decided in future
	Continue to operate unit			Dale Site transmission capability study required
	No major capital programs	Dale 2	Operate/Determine retire date/Regular O&M	
Cooper2	Continous emmissions monitoring	Dale 3	Repower with CFB 5/31/2014	
	Continue to operate unit		Utilize existing Steam Turbine	
	No major capital programs	Dale 4	Repower with CFB 5/31/2014	
			Utilize existing Steam Turbine	

Burns & McDonnell developed performance data, capital cost estimates, and operation and maintenance cost estimates of each options shown above (details in Section 4.0). This information was then utilized in a levelized busbar analysis to provide an economic ranking of each option. The methodology for this analysis is described in Section 2.1 and assumptions incorporated are discussed in Section 2.3. Detailed results are outlined in Section 5.0, but a summary of the economic results is shown in Table 1-2 below:

Table 1-2

Summary of Case Cost Breakdown

Busbar Analysis Results		Excluding Carbon Tax		Including Carbon Tax	
		Total All Costs (2) and/or Market Purchases $/yr x 1000	Total All Costs and/or Market Purchases $/MWh	Total All Costs and/or Market Purchases $/yr x 1000	Total All Costs and/or Market Purchases $/MWh
Cases (1)		EAC(3)	EAC(3)	EAC(3)	EAC(3)
Case H	Repower Dale 3 & 4 with CFB	$218,823	$71.27	$255,646	$83.29
Case D	Repower Cooper 2 with CFB	$237,070	$72.88	$274,314	$84.25
Case F	Repower Dale 3 & 4 Combined Cycle (2-1x1 7FA)	$346,224	$73.64	$386,490	$81.66
Case G	Repower Dale 3 & 4 Combined Cycle (2-1x1 7EA)	$289,664	$75.60	$324,323	$84.33
Case B-1	Cooper 2 Wet Scrubber - Avg Sulfur	$237,769	$76.72	273,025	$88.10
Case B-2	Cooper 2 Wet Scrubber - High Sulfur	$239,142	$77.16	274,398	$88.54
Case A-1	Cooper 2 Dry Scrubber - Avg Sulfur	$240,430	$77.58	275,686	$88.96
Case C-2	Cooper 1 & 2 Wet Scrubber - High Sulfur	$244,809	$78.34	280,397	$89.72
Case C-1	Cooper 1 & 2 Wet Scrubber - Avg Sulfur	$246,048	$78.74	281,635	$90.11
Case A-2	Cooper 2 Dry Scrubber - High Sulfur	$253,347	$81.75	288,603	$93.12
Note (1)	*Case results sorted by $/MWh*, No Carbon Tax				
Note (2)	"Total All Costs" Include: Capital, Fuel, Fixed O&M, Variable O&M, Major Maintenace at 70% Capacity Factor				
Note (3)	"EAC" = "Equivalent Annual Cost" for period 2007 thru 2035				

The levelized busbar costs as shown in the table above were generated based on certain assumptions (discussed in Section 2.0) regarding future market conditions for construction and operation of solid fuel and gas-fired generation resources. While Burns & McDonnell believes the use of these assumptions is reasonable for the purposes of this Study, Burns & McDonell makes no representations or warranties regarding future market costs, inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, the estimated costs presented in this Study may vary. For example, capital cost estimate of each Case have been established based on making appropriate site changes to accommodate necessary equipment footprints. If, as more detailed evaluations are made, that is not the outcome, the relative benefits of one Case to another may change.

It is the opinion of Burns & McDonnell that before a decision is made by EKPC on further course of action that detailed production cost runs be performed. This analysis, in addition to the busbar analysis, will determine how each option fits into the EKPC system dispatch. It is possible that the relative rankings of Cases could change with the production cost analysis vs. the busbar analysis.

2.0 OVERVIEW OF THE STUDY

In this section of the report, the Approach / Methodology of the Study is discussed. In addition, key assumptions utilized in the Study are discussed as well as key factors such as the transmission analysis and site remediation estimates.

2.1 APPROACH / METHODOLOGY

Several distinct steps were performed in completing this study:

- Evaluation of Consent Decree (discussed in Section 2.1.1 below)
- Plant Assessments (Section 2.1.2)
- Selection of Cases for Evaluation (Section 2.1.3)
- Input Data Development (Section 2.1.4)
- Busbar Economic Evaluation (Section 2.1.5)

2.1.1 *Evaluation of Consent Decree*

The Environmental Studies and Permitting group at Burns & McDonnell performed a review of Consent Decree in ascertain the options available to EKPC. This review is discussed in the following sections:

- Regulatory Analysis (Section 2.1.1.1)
- Dale Requirements (2.1.1.2)
- Cooper Unit 1 Requirements (2.1.1.3)
- Cooper Unit 2 Requirements (2.1.1.4)
- Requirements for All Units (2.1.1.5)

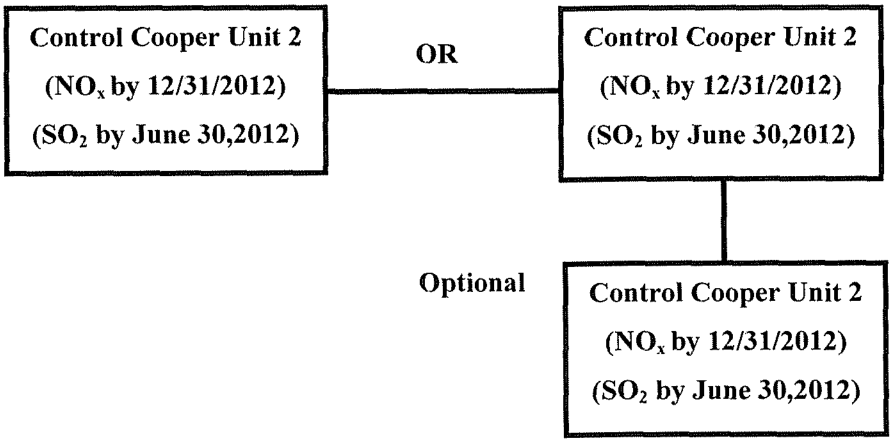
2.1.1.1 Regulatory Analysis

The United States Environmental Protection Agency (EPA) filed a complaint against East Kentucky Power Cooperative, Inc. (EKPC) which resulted in restrictions placed on emission rates and monitoring of nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM), and mercury (Hg). This section serves to summarize the restrictions mandated in the Consent Decree for Cooper and Dale generating stations issued by the United States District Court Eastern District of Kentucky Central Division Lexington. The requirements for the Spurlock station are outside of Burns & McDonnell's scope and are omitted from this report.

The EPA has given EKPC the option to either install and continuously operate NO_x and SO_2 emission controls at Cooper Unit 2 or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012 (Figure 2-1).

Figure 2-1

Decision Flow Chart



Please note, the consent decree specifies that the particulate limits are for front half (filterable) particulate.

The decision to either install new emission controls at Cooper Unit 2 or retire Dale Units 3 and 4 must be submitted in writing to the EPA no later than December 21, 2009.

2.1.1.2 Dale Requirements

EKPC can re-power Dale Units 3 and 4 as long as any existing pulverized coal boiler is replaced with a new circulating fluidized bed (CFB) or other clean coal technology of equivalent environmental performance that achieves minimum limitations shown in Table 2-1.

Table 2-1

Limitations for Re-powering of Dale Units 3 and 4

Pollutant	Emission Rate Limit*
NO_x	0.070
SO_2**	0.100
PM	0.015

*30-day rolling average (lb/MMBtu)

**Or a 30-day rolling average SO_2 removal rate of at least 95%

2.1.1.3 Cooper Unit 1 Requirements

A PM continuous emission monitoring system (CEMS) must be installed on Cooper Unit 1. Associated deadlines are shown in Table 2-2. The CEMS is to directly or indirectly measure PM concentration on an hourly average basis and a diluent monitor is to be used to convert the concentration to units of lb/MMBtu. All hourly average emission values are to be kept in an electronic database and reported to the EPA in electronic format on a 3-hour, 24-hour, 30-day, and 365-day rolling average basis.

Table 2-2

PM CEMS Deadlines

Action	Deadline
Submit plan for the installation and certification	Within 6 months of Consent Decree entry
Submit a Quality Assurance/ Quality Control protocol	120 days prior to December 31, 2012
Install and operate CEMS	December 31, 2012
Test CEMS to determine compliance	Within 90 days following December 31, 2012
Submit alternative monitoring plan or present infeasibility of CEMS	After 2 years of operation

2.1.1.4 Cooper Unit 2 Requirements

If EKPC chooses to install and operate NO_x and SO_2 emission controls at Cooper Unit 2, then specific requirements are mandated for the Unit (See Table 2-3). All control devices must be installed and operational before each due date. If an alternative equivalent control device is desired, EKPC must submit a written notice to and receive a written approval from the EPA prior to installing and operating the device.

Table 2-3

Cooper Unit 2 Control Devices

Pollutant	Control Device	Emission Limit[1]	Deadline
NO_x	SCR or Equivalent[2]	0.080	December 31, 2012
SO_2	FGD or Equivalent[3]	0.100	June 30, 2012
PM	Control Device	0.030	90 days after Consent Decree Entry

[1]30-day rolling average (lb/MMBtu)

[2]Equivalent NO_x control technology must have at least 90% NO_x reduction and 30-day rolling average less than 0.080 lb/ MMBtu

[3]Equivalent SO_2 control technology must have at least 95% SO_2 reduction with a 30-day rolling average less than 0.100 lb/ MMBtu

2.1.1.5 Requirements for all Units

The Consent Decree has several requirements which are applicable to all units in the EKPC system.

1. NO_x CEMS
2. SO_2 CEMS
3. Annual PM stack test
4. PM control device to achieve 0.030 lb/MMBtu emission rate
5. Low NO_x burners
6. System-wide NO_x and SO_2 limits

NO_x and SO_2 CEMS must be installed and continually operated on every EKPC unit. Emission rates measured by the CEMS will be used to determine NO_x and SO_2 compliance in accordance with 40 CFR Part 75 and the Consent Decree.

An annual PM stack test[1] is required for each EKPC unit. Any stack test performed to comply with a permit for the Kentucky Natural Resources and Environmental Protection Cabinet may be used to satisfy the Consent Decree requirement. The results[2] of the stack test must be submitted to the EPA within 30 days of completion of each test. A biannual stack test may be substituted for the annual test providing that:

- The two most recent tests are less than or equal to 0.015 lb/MMBtu, or
- The Unit is equipped with a PM CEMS.

EKPC is to install and operate a PM control device on each unit. Associated deadlines are shown in Table 2-4. EKPC may elect to upgrade existing PM control devices. If an upgrade is desired, a PM Pollution Control Upgrade Analysis is required unless it is a complete replacement of an existing device or the cost of refurbishing an existing device costs equal to or more than a complete replacement (on a total dollar-per-ton-of-pollutant-removed basis).

[1] In accordance with 40 CFR Part 60, Appendix A or any federally approved method contained in the Kentucky State Implementation Plan (SIP)
[2] In accordance with 40 CFR Part 60.8(f)

Table 2-4

PM Control Device Deadlines

Action	Deadline
Install and operate control device	Within 90 days from Consent Decree entry
Optimize plate-cleaning and discharge-electrode cleaning	Within 270 days from Consent Decree entry
Demonstrate each unit is in compliance*	Within 365 days from Consent Decree entry
Submit control device upgrade proposal	Within 180 days of compliance demonstration date
Upgraded control device begins operation	Within 1 year from upgrade approval

*Must verify that unit can achieve and maintain less than or equal to 0.030 lb/MMBtu for a 30-day rolling average

Twelve month rolling tonnage limitations apply to the entire EKPC system (See Table 2-5). Compliance is determined 12 months following the commencement date and ends on the date that the subsequent limit, if any, takes effect.

Table 2-5

EKPC System-Wide NO_x and SO_2 12-Month

Rolling Tonnage Limitation

Pollutant	Commencement Date	Limit (tons)
NO_x	January 1, 2008	11,500
	January 1, 2013	8,500
	January 1, 2015	8,000
SO_2	October 1, 2008	57,000
	July 1, 2011	40,000
	January 1, 2013	28,000

2.1.2 Plant Assessments

Burns & McDonnell first provided EKPC with an initial data request after which plant site visits to both Dale and Cooper plants were performed. Burns & McDonnell project team personnel met with appropriate plant personnel at each site to discuss operational matters and review all information pertinent to this Study. After the site visits several additional iterations were performed in order to insure that the most recent and accurate data and information were obtained. Results of the plant assessment are contained in Section 3.0 of this report.

2.1.3 Selection of Cases for Evaluation

Burns & McDonnell in conjunction with EKPC considered a number of different options in meeting the obligations of the Consent Decree. Four options related to the disposition of Cooper Unit 2 and four options related to the disposition of Dale Units 3 and 4 were considered. The features of each option are outlined in Table 2-6 below:

Table 2-6

Cases Analyzed to Satisfy Consent Decree

CASE A - COOPER 2 DRY SCRUBBER				NOTES/FEATURES
Cooper 1	Continuous Emissions Monitoring	Dale 1	Operate/Determine retire date/Regular O&M	Separates Cooper 1&2 completely (no common stack)
Cooper 2	SDA	Dale 2	Operate/Determine retire date/Regular O&M	
	Baghouse			
	Stack	Dale 3	Operate/Determine retire date/Regular O&M	
	SCR			
	Booster Fan	Dale 4	Operate/Determine retire date/Regular O&M	
CASE B - COOPER 2 WET SCRUBBER				NOTES/FEATURES
Cooper 1	Continuous Emissions Monitoring	Dale 1	Operate/Determine retire date/Regular O&M	Separates Cooper 1&2 completely (no common stack)
Cooper 2	WFGD	Dale 2	Operate/Determine retire date/Regular O&M	
	ESP Upgrades			
	Stack	Dale 3	Operate/Determine retire date/Regular O&M	
	SCR			
	Booster Fan	Dale 4	Operate/Determine retire date/Regular O&M	
CASE C - COOPER 1&2 - WET SCRUBBERS				NOTES/FEATURES
Cooper 1	Combined Cooper 1 & 2 Wet Scrubber (WFGD)	Dale 1	Operate/Determine retire date/Regular O&M	
	Cooper 1 ESP Upgrades			Dale retirement can be decided in future
	Cooper 1 SCR	Dale 2	Operate/Determine retire date/Regular O&M	Cooper baghouse optional
				Cooper 1&2 become virtually single unit
Cooper2	Combined Cooper 1 & 2 Wet Scrubber (WFGD)	Dale 3	Operate/Determine retire date/Regular O&M	Cooper Site transmission capability study required
	Cooper 2 ESP Upgrades			
	Cooper Stack (2 Liners/1 Shell)	Dale 4	Operate/Determine retire date/Regular O&M	
	Cooper 2 SCR			
CASE D - COOPER 1&2 - REPOWER WITH CFB				NOTES/FEATURES
Cooper 1	Combined Cooper 1 & 2 Wet Scrubber (WFGD)	Dale 1	Operate/Determine retire date/Regular O&M	
	Cooper 1 ESP Upgrades			Dale retirement can be decided in future
	Cooper 1 SCR	Dale 2	Operate/Determine retire date/Regular O&M	Cooper Site transmission capability study required
Cooper2	Combined Cooper 1 & 2 Wet Scrubber (WFGD)	Dale 3	*Operate/Determine retire date/Regular O&M*	
	Cooper 2 ESP Upgrades			
	Cooper Stack (2 Liners/1 Shell)	Dale 4	Operate/Determine retire date/Regular O&M	
	Cooper 2 SCR			
CASE E - RETIRE DALE 1-4				NOTES/FEATURES
Cooper 1	Continous ommissions monitoring	Dale 1	Shut down 12/31/2012	
	Continue to operate unit			
	No major capital programs	Dale 2	Shut down 12/31/2012	
Cooper 2	Continous ommissions monitoring	Dale 3	Shut down 12/31/2012	
	Continue to operate unit			
	No major capital programs	Dale 4	Shut down 12/31/2012	
CASE F - REPOWER DALE 3&4 WITH COMBINED CYCLE (2-1x1 7FA)				*NOTES/FEATURES*
Cooper 1	Continous ommissions monitoring	Dale 1	Operate until next major overhaul - then retire	Dale 1&2 retirement can be decided in future
	Continue to operate unit		Regular O&M	Dale Site transmission capability study required
	No major capital programs			
		Dale 2	Operate until next major overhaul - then retire	
Cooper 2	Continous ommissions monitoring		Regular O&M	
	Continue to operate unit			
	No major capital programs	Dale 3	Re-Power with Combined Cycle 5/31/2014	
			Utilize existing Steam Turbine	
		Dale 4	Re-Power with Combined Cycle 5/31/2014	
			Utilize existing Steam Turbine	
CASE G - REPOWER DALE 3&4 WITH COMBINED CYCLE (2-1x1 7EA)				NOTES/FEATURES
Cooper 1	Continous ommissions monitoring	Dale 1	Operate until next major overhaul - then retire	Dale 1&2 retirement can be decided in future
	Continue to operate unit		Regular O&M	*Dale Site transmission capability study required*
	No major capital programs			
		Dale 2	Operate until next major overhaul - then retire	
Cooper 2	Continous ommissions monitoring		Regular O&M	
	Continue to operate unit			
	No major capital programs	Dale 3	Re-Power with Combined Cycle 5/31/2014	
			Utilize existing Steam Turbine	
		Dale 4	Re-Power with Combined Cycle 5/31/2014	
			Utilize existing Steam Turbine	
CASE H - REPOWER DALE 3&4 WITH CFB				NOTES/FEATURES
Cooper 1	Continous ommissions monitoring	Dale 1	Operate/Determine retire date/Regular O&M	Dale 1&2 retirement can be decided in future
	Continue to operate unit			Dale Site transmission capability study required
	No major capital programs	Dale 2	Operate/Determine retire date/Regular O&M	
Cooper2	Continous ommissions monitoring	Dale 3	Repower with CFB 5/31/2014	
	Continue to operate unit		Utilize existing Steam Turbine	
	No major capital programs	Dale 4	Repower with CFB 5/31/2014	
			Utilize existing Steam Turbine	

2.1.4 Input Data Development

For all cases considered Burns & McDonnell developed conceptual / budgetary capital cost, operation and maintenance, and performance data for input to the economic analysis. This data came from existing databases at Burns & McDonnell and, in some cases, current quotes from vendors and equipment suppliers.

2.1.5 Busbar Economic Evaluation

In addition to the evaluation of the technical, environmental, and regulatory factors that impact each case studied, an evaluation of the relative economic merits of each case was performed.

The economic evaluation performed by Burns & McDonnell consisted of a "busbar" analysis in which the capital requirements and the operating and maintenance costs for each unit at either the Dale Station and the Cooper Station were simulated for the period 2007 through 2035. This analysis was performed using a detailed busbar costs model developed by Burns & McDonnell and adapted specifically for this Study. Important features of the bus-bar model and the analysis performed are as follows:

- The model simulated unit operations by year, though it does have the ability to recognize changes in facilities and costs with any particular year.
- Operations and costs were modeled using a wide variety of variables including:
    - Unit size, availability, heat rate, etc.
    - Major operating costs such as fuel, fixed and variable O&M, and major maintenance costs.
    - For fuel, the model factored fuel type and costs, depending upon what fuel was being used in any particular year or portion of a year.
    - The simulations of costs included all capital costs associated with the implementation of a particular option at a particular unit at a specified point in time.
    - Depending upon the particular case examined, market purchase prices were included. Market purchase costs were based on the MISO power market at the EKPC node and included day-ahead Locational Margin Prices (LMPs), capacity market costs, and Network Integrated Transmission (NITS) costs.
    - The market prices used in the analysis also included a 15 percent "energy management fee" under the assumption that EKPC would elect to use such a resource to carry out market transactions.

- Model runs were made with and without carbon taxes being applied to the operating units. In those cases were carbon taxes were applied, it was assumed that such taxes would commence in 2015.

Appendix F presents key summary tables of model output results for each case studied. The results shown are for model runs assuming an 80 percent capacity factor. Also shown for each case are the graphs of the levelized bus-bar costs (Equivalent Annual Costs, EAC) for a range of capacity factors for each of the Dale and Cooper Stations and for the combined results.

For purposes of comparing one case against another, a key measure of economic merit is the present value of total costs and the levelized annual cost ($/MWh) for each case. These key measures of economic performance are also shown in the tables in Appendix F.

As a final point, it must be noted that the bus-bar analysis performed in this Study was designed to estimate the cost of each case (by unit and station) on a "stand alone" basis. The results there would best serve to compare one specific case against another. No attempt was made to evaluate the operation and costs of each unit within the broader picture of an integrated system-wide resource plan. Such an analysis was not within the scope of this Study and will be performed by EKPC.

In addition to coal and natural gas prices, it was also necessary to provide some indication of the cost of purchased power, as it was assumed for purposes of case definition that EKPC would buy from the market during those periods when a particular unit would be out of service. It was further assumed that such transition periods would last three months. The market costs presented in this report were developed by applying a weighted average of coal and natural gas prices, recognizing these two variables represent key power marker drivers. The estimated LMP was then adjusted to reflect estimated capacity market costs, and the cost of Network Integrated Transmission Service (NITS). The resultant price estimated was further adjusted to reflect a 15 percent energy management fee and a possible cost adder to congestion. Finally, beginning in 2015, the price of market purchases was increased by $7.5 per MWh to represent a carbon tax of generation.

2.2 KEY ASSUMPTIONS

In preparing this Report, Burns & McDonnell worked closely with EKPC personnel and relied to a great extent on information provided by EKPC. This information included system and unit operating and cost data, and certain studies performed internally by EKPC, such as the transmission study presented herein.

Given the wide range of variables considered, it was therefore necessary to make a number of assumptions regarding future events. Effort was made to evaluate those assumptions based upon professional experience, available historical data, as well as realistic expectations of future events. However, given the uncertainties associated with any planning study, such as the cost of coal and natural gas and the capital costs of new generation, no guarantee can be made that actual events depicted in this Report will conform to the assumptions described herein. To the extent that future events may differ from the assumptions contained in this Report, such differences may have a significant effect on the findings and conclusions contained herein. Presented below is a summary of key assumptions that were employed in the Study.

2.2.1 Economic Parameters

Key economic assumptions include:

- General inflation rate of 2.5 percent.
- Interest rate of 6 percent
- Discount rate of 10 percent
- Amortization period of 25 years

Capital costs for specific options were escalated to the appropriate "commercial operation date" of the specific capital program under study.

As appropriate, current cost estimates were escalated at the general inflation rate of 2.5 percent.

2.2.2 Fuel Costs - Coal

For fuel, the economic model recognized different fuel prices, depending upon what fuel was being used in any particular year or portion of a year. Burns & McDonnell employed a number of sources for fuel price projections including, Hill & Associates and the Department of Energy, Energy Information Agency (EIA) projections. Hill & Associates is a nationally recognized coal market analysis firm and has participated with Burns & McDonnell on numerous studies. Using this expertise, Burns & McDonnell incorporated coal prices that were differentiated by coal type, sulfur content, and transportation costs to the Dale and Cooper stations. It should also be noted that Burns & McDonnell also relied to a very considerable extent on the experience and expertise of EKPC regarding the regional market for coal and delivered coal prices to each station. Table 2-7 presents summary forecasts of key coal prices used in the Study. Appendix D provides the detailed coal analysis and forecast developed by Hill & Associates. Even though rail transportation values were provided by H&A, rail is currently not used at either facility.

Table 2-7

Forecast of Delivered Coal Prices (Nominal $)

Year	Dale Mid-Sulfur (Truck)	Dale High Sulfur (Truck)	Cooper Mid-Sulfur (Truck)	Cooper High Sulfur (Truck)
	$/mmBtu	$/mmBtu	$/mmBtu	$/mmBtu
2008	$2.342	$2.134	$2.280	$2.068
2010	$2.417	$2.198	$2.350	$2.127
2012	$2.483	$2.253	$2.412	$2.178
2014	$2.662	$2.420	$2.588	$2.342
2016	$2.796	$2.542	$2.719	$2.460
2018	$2.991	$2.724	$2.910	$2.639
2020	$3.246	$2.965	$3.162	$2.878
2022	$3.490	$3.195	$3.404	$3.104
2024	$3.811	$3.502	$3.723	$3.409
2026	$3.982	$3.658	$3.890	$3.559
2028	$4.138	$3.797	$4.040	$3.693
2030	$4.300	$3.941	$4.196	$3.831
2032	$4.467	$4.091	$4.357	$3.975
2034	$4.642	$4.246	$4.526	$4.124

2.2.3 Fuel Costs – Natural Gas

Natural gas prices play a key role in simulating the operating costs of selected cases, but natural gas prices are a major determinant in the price of electricity purchased in the market. Regarding natural gas price projections, the basic starting point was the natural gas price forecast that is prepared by EIA. The EIA forecast was then used in conjunction with NYMEX futures to estimate both the short term and the longer term natural gas markets. Table 2-8 and Figure 2-2 present our current best assessment of forward-looking natural gas prices. The mid-range prices were used in this Study.

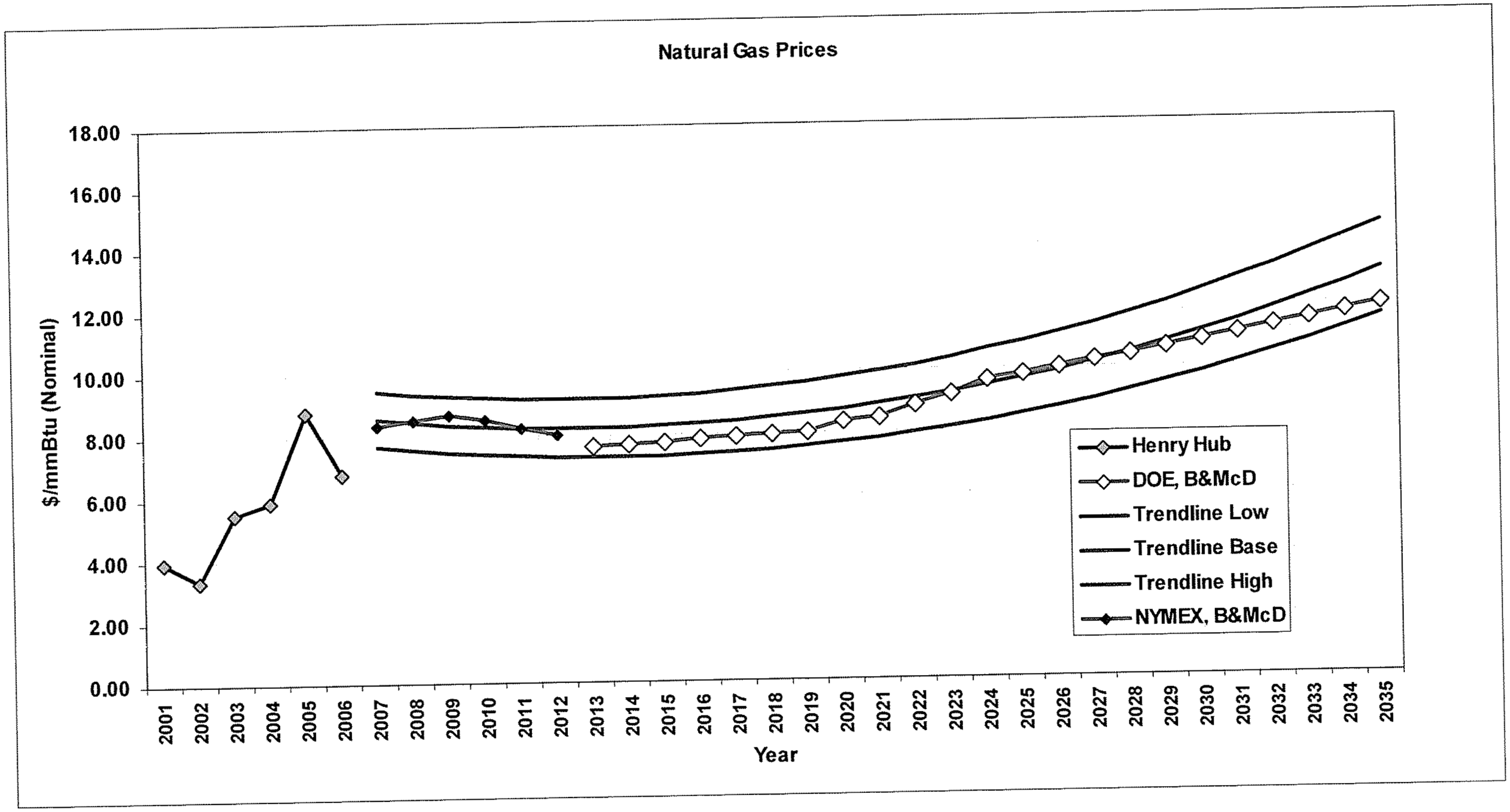
Table 2-8

Forecast of Natural Gas Prices (Nominal $)

Year	Henry Hub Spot	B&McD NYMEX DOE	Forecast - Trendline Low	Forecast - Trendline Base	Forecast - Trendline High
	Avg $/mmBtu	Avg $/mmBtu	Avg $/mmBtu	Avg $/mmBtu	Avg $/mmBtu
2001	$3.96				
2002	$3.35				
2003	$5.52				
2004	$5.90				
2005	$8.79				
2006	$6.76				
2008		$8.48	$7.54	$8.44	$9.33
2010		$8.49	$7.38	$8.29	$9.20
2012		$7.98	$7.29	$8.22	$9.15
2014		$7.69	$7.28	$8.23	$9.19
2016		$7.82	$7.33	$8.32	$9.30
2018		$7.93	$7.46	$8.48	$9.50
2020		$8.32	$7.66	$8.72	$9.78
2022		$8.82	$7.94	$9.04	$10.14
2024		$9.60	$8.29	$9.44	$10.58
2026		$10.00	$8.71	$9.91	$11.12
2028		$10.40	$9.21	$10.47	$11.73
2030		$10.82	$9.79	$11.11	$12.43
2032		$11.26	$10.44	$11.83	$13.22
2034		$11.71	$11.17	$12.64	$14.10

Figure 2-2

Natural Gas Prices – Historical and Forecast (Nominal $/MMBtu)



2.2.4 Natural Gas Availability and Delivery

Burns & McDonnell engaged in discussion with local personnel and with personnel in Houston regarding the general availability of natural gas to service selected cases in this Study. Given the relative costs between natural gas and coal and given preliminary results that indicted that the natural gas generation option were not as competitive as other coal options, the issue of natural gas deliverability was limited to a surveillance level of consideration. The basic conclusion reached was that natural gas could be made available for additional EKPC generation, given the relative closeness of major gas transmission facilities. Also, base on recent studies performed by Burns & McDonnell we employed in the Study a pipeline installation cost of $1,000,000 per mile (current $) with a 20 percent contingency applied. We further assumed a five (5) mile length of pipeline would be needed.

2.2.5 Purchased Power

Burns & McDonnell evaluated local power market prices by using detailed hourly price data available from MISO at the EKPC node. The cost of purchased power from the MISO market entered into the analysis at a number of key points. Most globally, for each case studied and for general reference purposes, the cost of being "naked to the market" was estimated. Theoretically, market purchases could always be viewed as an alternative to any particular course of action. The estimates of the cost of power market prices used in the Study are shown in Table 2-9 and Figure 2-3.

Table 2-9

Forecast of MISO Day-Ahead LMP @"EKPC" (Nominal $)l

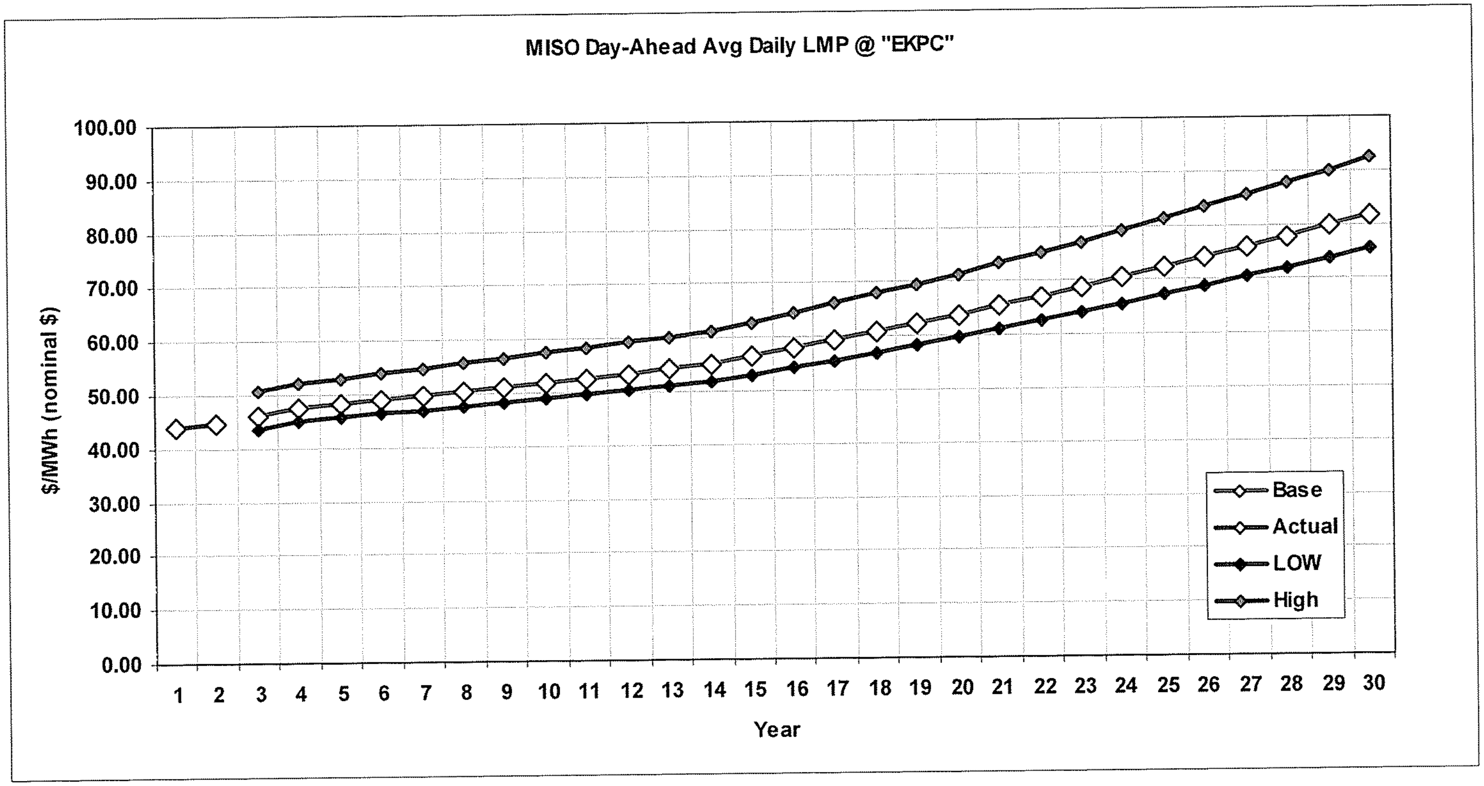
	MISO Average Day Ahead LMP		
	Low	Base	High
Year	Avg Daily LMP for Year	Avg Daily LMP for Year	Avg Daily LMP for Year
	Nominal $ $/MWh	Nominal $ $/MWh	Nominal $ $/MWh
2006	$43.86	$43.86	$43.86
2007	$44.74	$44.74	$44.74
2008	$43.69	$45.99	$50.59
2010	$45.58	$48.08	$52.99
2012	$46.87	$49.54	$54.71
2014	$48.20	$51.04	$56.48
2016	$49.56	$52.59	$58.31
2018	$50.96	$54.18	$60.20
2020	$52.92	$56.38	$62.76
2022	$55.50	$59.24	$66.09
2024	$58.20	$62.25	$69.58
2026	$61.04	$65.42	$73.27
2028	$64.01	$68.74	$77.15
2030	$67.13	$72.24	$81.23
2032	$70.40	$75.91	$85.53
2034	$73.84	$79.77	$90.06

The cost of market purchase also had direct impact on the specific case that examined the retirement of all four units at Dale. For this case, it was assumed that the generation lost by such a retirement would be made up to the EKPC system through market purchases.

Additionally, it was assumed that market purchases would be made during the relatively short transition periods between the termination of operations by an existing facility and the startup of the new generating facility. For purposes of the Study, it was assumed that market purchases would be made for a period of one month.

Figure 2-3

Forecast of MISO Day-Ahead LMP @"EKPC" (Nominal $)l Gas Prices (Nominal $)



2.2.6 Carbon Tax

Uncertainty currently exists regarding the magnitude and timing of a "carbon tax". However, such a tax is a distinct possibility and our Study examined the potential impacts for each case analyzed. In particular, we assumed that the carbon tax on coal technologies would be $10 per MWh (2007$) and the tax on natural gas technologies (combined cycle) would be $4.7 per MWh (2007$). Additionally, we assumed the impact of such a tax on power market prices would be $7.4 per MW (2007$).

2.3 TRANSMISSION ANALYSIS

Depending on the specific case considered, important consequences may result from a transmission system perspective. Burns & McDonnell relied on the transmission study performed by EKPC personnel, as attached herein (Appendix A). The specific transmission system upgrade costs that are presented in the EKPC study were incorporated into the Burns & McDonnell Study.

Regarding the generation scenarios at the Dale Power Station, two differenet transmission scenarios were evaluated: 1) a 650 MW Dale station output, and 2) 0 MW Dale Station output.

The current total capacity of Dale power plant is 196 MW. For scenario 1), the 650 MW generation scenario will increase the output by 454 MW, which would add significant loading to the transmission system and result in overloaded facilities. The analysis result showed nine overloaded facilities and a five voltage violations. The study presented a system upgrade plan to mitigate the overload and voltage violations which amounted to $18.4 Million (2007).

For the second scenario for 0 MW generation output, ten low voltage violations were reported. This is due to the loss of the reactive power support from the existing Dale power plant. A new 138/69 kV substation at Newby and three capacitor banks were suggested to address the problem. This was estimated to cost $4.1 Million (2007) and was incorporated in busbar runs for Dale retirement cases.

2.4 SITE REMEDIATION COSTS

A site remediation cost evaluation was performed for all cases involving the Dale site. A summary of the costs contained in each remediation category are shown in the table below. Case E (retire all units completely) incorporates all remediation cost categories. Cases F and G (repower with combined cycle natural gas units) retire the existing Dale boilers in place and retire the ash ponds and coal pile area since coal is no longer needed. The ash ponds and coal pile area are maintained in Case H (repower with CFB), but the existing boilers are completely demolished and removed to allow room for the new CFB. Table 2-

10 contains the summary of site remediation costs. A detailed breakdown of all remediation costs are shown in Appendix E.

Table 2-10

Site Remediation Cost Summary

	Case E	Case F	Case G	Case H
Retire Unit 1 & 2 Boilers	$2,026,000	$50,650 [1]	$50,650 [1]	$2,026,000
Retire Unit 3 & 4 Boilers	$3,043,000	$76,075 [1]	$76,075 [1]	$3,043,000
Close North Ash Pond	$946,000	$946,000	$946,000	$0
Close South Ash Pond	$924,000	$924,000	$924,000	$0
Remediate Coal Pile Area	$268,000	$268,000	$268,000	$0
Prepare Site for Retirement and Abandonment without Full Demolition	$550,000	$0	$0	$0
Subtotal	**$7,757,000**	**$2,264,725**	**$2,264,725**	**$5,069,000**
Contingency (20%)	**$1,551,400**	**$452,945**	**$452,945**	**$1,013,800**
Total	**$9,308,400**	**$2,717,670**	**$2,717,670**	**$6,082,800**

[1] For the cases in which the Boilers are not fully demolished but retired in place, the main steam lines will be cut and an asbestos inspection will be performed to ensure that no friable asbestos is present, and if any is discovered, it is remediated.

* * * * *

3.0 PLANT ASSESSMENT EVALUATION

3.1 DALE POWER STATION

The following is a brief description of each of the four units at Dale station and major equipment replacement or upgrades.

3.1.1 Dale: Units 1& 2

The boilers were designed and manufactured by Foster Wheeler, and the turbine/generators by General Electric. Units 1 & 2 were commissioned in 1952.

3.1.2 Dale: Unit 1

The boiler is natural circulation, pulverized coal-fired, with superheated steam operating at a drum pressure of 925 psig. Steam outlet Maximum Continuous Rating (MCR) flow rate is 220,000 lbs/hr at 900°F. The unit is non-reheat design. Boiler water walls are of tangent tube type with refractory between the tubes.

In 1999 a condition assessment was performed on the units by Foster Wheeler. It included visual inspections, non-destructive testing involving tube ultra-sonic thickness measurements, and magnetic particle testing of the Finishing Superheater (FSH) tube-to-header stubs, FSH header and main steam line replications. The water wall headers were examined by using a boroscope. Destructive testing was performed on selected tube samples. Results from the condition assessment were that the boilers were in reasonably good condition given their age and operating hours of service. The major problems discovered were secondary super heater outlet header metallurgical deficiencies, boiler water side scale deposits and a few isolated boiler tubes with short remaining life. The replications taken on the finishing superheater outlet headers and main steam line yielded results indicating creep and micro-cracking. These are advanced stages of metal fatigue resulting in very minimal remaining life.

Unit upgrades and improvements:

- New superheater tubes were installed in 1975.
- A precipitator for removal of particulate was added in fall of 1979.
- Turbine/generators for Unit 1 were replaced in 1998. It is a condensing, non-reheat design.
- New Bailey controls were installed in 1998.
- New coal feeders to the pulverizers were installed in 1998.

- Feedwater heater 1-1, 1-2, & 1-4 were replaced with new feedwater heaters in 1999.
- New Byron Jackson condensate pumps and motors were installed in 2000.
- The boiler slope wall tubes were replaced in 2006.
- The unit was upgraded with low NO_x burners in 2007.

3.1.3 Dale: Unit 2

The boiler is natural circulation, pulverized coal-fired, with superheated steam operating at a drum pressure of 925 psig. Steam outlet MCR flow rate is 220,000 lbs/hr at 900°F. The unit is non-reheat design. Boiler water walls are of tangent tube type with refractory between the tubes.

In 1999 a condition assessment was performed on the unit by Foster Wheeler. It included visual inspections, non-destructive testing involving tube ultra-sonic thickness measurements, and magnetic particle testing of the FSH tube to header stubs, FSH header and main steam line replications. The water wall headers were examined using a boroscope. Destructive testing was performed on selected tube samples. Results of the condition assessment were that the boilers were in reasonably good condition given there age and operating hours of service. The major problems discovered were secondary super heater outlet header metallurgical deficiencies, boiler water side scale deposits and a few isolated boiler tubes with short remaining life. The replications taken on the finishing superheater outlet headers and main steam line yielded results indicating creep and micro-cracking. These are advanced stages of metal fatigue resulting in very minimal remaining life.

Unit upgrades and improvements:

- New superheater tubes were installed in 1975 and again in 1984.
- A precipitator for removal of particulate was added in fall of 1979.
- Turbine/generators for unit 2 were replaced in 1998. It is a condensing, non-reheat design.
- New Bailey controls were installed in 1998.
- New coal feeders to the pulverizers were installed in 1998.
- Feedwater heater 2-1, 2-2 & 2-4 were replaced with new feedwater heaters in 1999.
- New Byron Jackson condensate pumps and motors were installed in 2000.
- The boiler slope wall tubes were replaced in 2006.
- The unit was upgraded with low NO_x burners in 2007.

3.1.4 Dale: Unit 3

The boiler was designed and manufactured by Riley Stoker Corp. and the turbine/generator by General Electric. The unit was commissioned in 1957.

The boiler is a natural circulation, pulverized coal-fired, with superheated steam operating at a drum pressure of 1475 psig. Steam outlet MCR flow rate is 640,000 lbs/hr at 950°F. The unit is a non-reheat design. Boiler water walls are of the tangent tube type with refractory between the tubes. The pulverizers are Attrita high speed hammer mill type. A condition assessment of the boiler was performed in spring of 1996 by Babcock & Wilcox (B&W). This condition assessment included non-destructive testing and visual examination. The results were typical of a unit of this age with no signs of end of life predictions. In the fall of 1999 Foster Wheeler performed a boiler inspection. Considering the age of the unit it was in good overall condition. Some water wall thinning was noted mostly in areas of sootblowing and in areas of refractory deterioration causing high velocities of gases. Refractory deterioration around roof seals had caused excessive amounts of fly ash in the penthouse.

Unit upgrades and improvements:

- Replaced primary and secondary superheaters in 1986.
- The turbine/generator was replaced in 1995. It is a condensing, non-reheat design.
- New low NO_x burners were installed in 1996.
- New Bailey controls we installed in 1996.
- Replaced the secondary superheater row 4 & 5 in 1996 and again with stainless steel 2000.
- Feedwater heater 3-1 had a bundle replacement in 1996.
- Feedwater heater 3-2 new in 1997.
- Feedwater heaters 3-4 & 3-5 new in 1999.

3.1.5 Dale: Unit 4

The boiler was designed and manufactured by B&W and the turbine/generator by General Electric. The unit was commissioned in 1960.

The boiler is a radiant heat, natural circulation, pulverized coal-fired, with superheated steam operating at a drum pressure of 1475 psig. Steam outlet MCR flow rate is 623,000 lbs/hr at 955°F. The unit is a non-reheat design. The unit was built as a pressurized unit and converted to balance draft in 1994. Pulverized coal from three EL '64 pulverizers is fired through nine B&W DRB-XCL low NO_x burners. Boiler water walls are of the tangent tube type with refractory between the tubes. In the spring of 2007 B&W

performed a boiler inspection. This inspection found wall thinning in the economizer section and screen tubes. This inspection was visual with some non-destructive wall thickness testing. Overall the unit was evaluated to be in fair condition. In the spring of 2006 B&W performed a boiler assessment with non-destructive testing and some tube samples. The economizer and water walls were showing universal thinning.

Unit upgrades and improvements:

- New low NO_x burners were installed in fall of 1995.
- The turbine/generator was replaced with 1996. It is a condensing, non-reheat design.

3.1.6 Assessment of Dale Station

Dale Power Station is the oldest station in EKPC's fleet. The remaining life for Dale Station as a coal-fired power station should be judged on heat rate, as well as other related factors such as approximate remaining life of major components of each unit or the sum of remaining life for the station, and the cost of fixed Operation and Maintenance (O&M) per kW and Variable O&M per MWh on a per station basis.

Dispatch heat rates at the operating limits for the four Dale Units are as follows:

Unit 1 .... 11,910 Btu/kW@24MW
Unit 2 .... 11,710 Btu/kW@24MW
Unit 3 .... 11,238 Btu/kW@75MW
Unit 4 .... 11,100 Btu/kW@75MW

Even though all four turbine/generator machines were new in the mid 1990's they were sized, to meet the maximum steam flow the boilers could produce. Each unit at the station had to remain a non-reheat design due to the boiler flow circuit and the related feedwater system. A review of the maintenance logs and capital expenditures would show that the units/station has been well maintained. Thermal cycle of utility boilers and balance of plant is a factor resulting in creep failure of stress components. Tube wall thinning is also a result of normal operation due to the combustion process metal deterioration over time occurs. Sootblowing, slagging and other combustion process accelerate the life remaining in the boiler tubes.

From the 2001 data provided, the ten year average for Dale Station's Fixed O&M cost per kW is $38.05 compared to the East Kentucky system average for coal-fired units of $27.83 or the newest station Spurlock with a $23.60 cost. The variable O&M cost per MWh for Dale Station is $2.24 compared to the East Kentucky system average for coal-fired units of $1.11 or the newest station Spurlock with a $1.01 cost.

During each unit's next major outage a thorough evaluation of the boiler, steam turbine, generator and other major components of the balance plant should be done to determine degradation in the equipment and requirements for repair and or replacement.

3.2 COOPER POWER STATION

The following is a brief description of Cooper Power Station and major equipment replacement or upgrades

3.2.1 Cooper: Unit 1

The boiler is a natural circulation, front wall fired, on pulverized coal, with superheat and reheat steam operating at a drum pressure of 1525 psig. Steam outlet Maximum Continuous Rating (MCR) flow rate is 785,700 lbs/hr at 1000°F/1000°F. At MCR the unit is rated for 117 Megawatts. Boiler water walls are membrane wall design. The unit was commissioned in 1965. The unit has a General Electric turbine/generator set with a condensing once through condenser.

In 2000 the boiler had extensive tube thickness test of the boiler water wall tubes and headers. These tests were performed by B&W. No significant tube and header loss of wall thickness was determined. Some cracks were note and repaired in bends in the burner area and sootblower openings. It has been determined that the reheater section of the boiler should be replaced in the near future. At that time the high energy piping was also tested and no significant issues were found. Low NO_x burners were installed in 1993.

The steam turbine and generator had a major overhaul in the fall of 2000. The turbine had a steam path audit performed on the HP-IP at the start of the outage. The general condition of the machine was found to be in good condition. The steam path audit determined that 3233 KW of losses existed in the HP and IP portion of the turbine, of which 2683 KW of losses were recovered by work done to the machine during the outage.

Through the years the balance of plant equipment has been maintained or upgraded to return the unit to original capacity.

- The pulverizer motors have been changed from 200hp to 350hp.

- The air heaters have been changed to Ljungstrom regenerative air preheaters in 1995. Seal clearances are check twice per year.
- The circulation water condenser was retubed in 1991.
- Unit 1 was converted from a forced draft unit to a balanced draft unit in 1988. The unit has two FD fans and one ID fan. All fans are operated with fluid drives.
- Feedwater heater No. 4 was retubed in 1987. Feedwater heater No. 2 is at 10% tube pluggage and should be considered for tube replacement.
- The unit controls were upgrade to Bailey DCS for the boiler and balance of plant in 1993 with GE Mark V turbine controls.

3.2.2 Cooper: Unit 2

The boiler is a natural circulation, front wall fired, on pulverized coal, with superheat and reheat steam operating at a drum pressure of 1890 psig. Steam outlet MCR flow rate is 1,550,000 lbs/hr at 1000°F/1000°F. At MCR the unit is rated for 227 Megawatts. Boiler water walls are membrane wall design. The unit was commissioned in 1969. The unit has a General Electric turbine/generator set with a condensing once through condenser.

In 2003 the boiler had extensive tube thickness test of the boiler water wall tubes and headers. These tests were performed by B&W. No significant tube and header loss of wall thickness was determined. Some cracks were noted and repaired in bends in the burner area and sootblower openings. The reheater section of the boiler has been replaced with stainless steel material 1988. The primary superheater tubes were replaced in 1994. The secondary superheater and screenwall tubes were replaced in 2000. The economizer tubes were replaced in 1993. At that time the high energy piping was also tested and no significant issues were found. Low NO_x burners were installed in 1994. The bottom ash hopper was changed to a drag chain design in 1993 with upgrades in 1995.

The steam turbine and generator had a major overhaul in the fall of 2003. The turbine had a steam path audit performed on the HP-IP at the start of the outage. The general condition of the machine was found to be in good condition. The recommendations are to continue operation of the machine with 10 year intervals of inspection and replacement and repair of components as determined by the inspections.

Through the years the balance of plant equipment has been maintained or upgraded to return the unit to original capacity.

- The pulverizer motors have been changed from 200 hp to 350 hp.

- The air heaters have been changed to Ljungstrom regenerative air preheaters in 1995. Seal clearances are check twice per year.
- The circulation water condenser was retubed in 1994.
- Unit 2 was converted from a forced draft unit to a balanced draft unit in 1989. The unit has two FD fans and two ID fan. All fans are operated with fluid drives.
- Feedwater heaters No. 5, 6, & 7 have been retubed in 1991, 1980 and 1992 respectively.
- The unit controls were upgrade to Bailey DCS for the boiler and balance of plant in 1993 with GE Mark V turbine controls.

3.2.3 Assessment of Cooper Station

Cooper Units 1 and 2 are mature units that have been well maintained throughout their service life. The remaining life for Cooper Station as a coal-fired power station should be judged on heat rate, as well as other related factors such as approximate remaining life of major components of each unit or the sum of remaining life for the station, and the cost of fixed O&M per kW and Variable O&M per MWh on a per station basis.

Dispatch heat rates at the operating limits for the two Cooper Units are as follows:

Unit 1 .... 9,916Btu/kW@116 MW
Unit 2 .... 10,125Btu/kW@225 MW

A heat rate below 10,200 Btu/kW would be found in today's reheat machines.

From the 2001 data provided, the ten year average for Cooper Station's Fixed O&M cost per kW is $33.13 compared to the East Kentucky system average for coal-fired units of $27.83 or the newest station Spurlock with a $23.60 cost. The variable O&M cost per MWh for Cooper Station is $0.80 compared to the East Kentucky system average for coal-fired units of $1.11 or the newest station Spurlock with a $1.01 cost.

From data provided for the ten year period from 1997 to 2006 for the average Operations and Maintenance Cost for Dale Station was $35.61Mills/kWh while for Cooper Station the comparable cost is $25.15Mills/kWh. This is a comparison that includes the sum of fuel burned cost, operation cost, and maintenance cost divided by net megawatts generated to give the total power cost.

During the period form 1997 to 2006 Unit 1 had an online availability factor of 88.41 and a net capacity factor of 75.15. The national average for units in the 100 to 199 MW size is 85.23 and 75.15

respectively. During the period from 1997 to 2006, Unit 2 had an online availability factor of 87.11 and a net capacity factor of 71.11. The national average for units in the 199 to 299 MW size is 85.04 and 68.40 respectively.

EKPC should consider retaining Cooper Stations Units 1 and 2 as a part of their operating fleet for the next 20 years. The units have been well maintained and should be expected to be reliable if they are continued to be maintained as they have been. The units have desirable heat rates, are above the national average for online availability and capacity factor and have competitive operation and maintenance cost for the region. During each unit's next major outage a thorough evaluation of the boiler, steam turbine, generator and other major components of the balance plant should be done to determine degradation in the equipment and requirements for repairs and or replacement.

* * * * *

4.0 CASE DESCRIPTIONS

A total of eight (8) different cases were evaluated to meet the requirements of the consent decree:

Case A: Dry Scrubber (SDA) added to Cooper Unit 2

Case B: Wet Scrubber (WFGD) added to Cooper Unit 2

Case C: Wet Scrubbers (WFGD) added to Cooper Units 1 and 2

Case D : Cooper Unit 1 and 2 Repowered with a Circulating Fluidized Bed (CFB) Unit

Case E: Retire Dale Units 1-4

Case F: Repower Dale Units 3-4 with 2-1on1 7FA Combined Cycle Units

Case G: Repower Dale Units 3-4 with 2-1on1 7EA Combined Cycle Units

Case H: Repower Dale Units 3-4 with a Circulating Fluidized Bed (CFB) Unit

Many more cases, in addition to those listed above, were considered. Some cases were eliminated via a preliminary screening process and some were identified as not technology-viable in the time frame needed for satisfying the consent decree. For example, Case E includes all four Dale Units, but the consent decree only addresses Units 3-4. In its screening analysis Burns & McDonnell found that there are not enough economic benefits to operate Dale Units 1 and 2 without operating Units 3 and 4.

Following below is a detailed environmental analysis of each case and a listed of the key performance, capital cost, and operating and maintenance costs developed by Burns & McDonnell. Following that is a breakdown of what items were included in some of categories that may not be obvious:

<u>Total Fixed O&M</u>: Staff salaries, benefits, administrative expenses, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.

<u>Variable O&M</u>: makeup water, water treatment, water disposal, limestone, ammonia, SCR catalyst replacement (when applicable), SCR catalyst disposal (when applicable), solid waste disposal, sorbent for SO_3 control, other consumables, and maintenance on equipment.

<u>Project Indirects</u>: Engineering, construction management, start-up engineering, construction power, performance testing, spare parts, performance and payment bond, EPC profit, on-site switchyard, initial fuel inventory, initial limestone inventory, permitting and licensing fees, and builder's risk insurance.

4.1 CASE A: COOPER 2 DRY SCRUBBER

In this case a SCR (for NO_X control) and a dry scrubber (SDA, for SO_2 control) are added to Cooper Unit 2. The SCR must be in operation by December 31, 2012 and the SDA must be in operation by August 30, 2012. Cooper Unit 1 continues to operate as before and a CEMS is added to both units. All four Dale Units continue to operate as usual with any retirement decisions being deferred until the next major overhaul.

4.1.1 Case A: Environmental Analysis

If EKPC decides to retrofit Cooper Unit 2 with SO_2 and NO_x controls, notification must be made to EPA by December 21, 2009.

The dry scrubber must achieve an emission rate of 0.100 lb SO_2/MMBtu (30-day rolling average) or achieve at least 95% reduction in SO_2 emissions. The scrubber must be operation by June 30, 2012. Compliance must be demonstrated in part through an SO_2 CEMS. Additionally, the system-wide SO_2 12-month rolling tonnage limits shown in Table 2-5 must be met. A removal percentage of 95% may be difficult to maintain on a long-term basis with a dry scrubber.

This option would likely require permitting for the new particulate emissions associated with the scrubber (material transfer and hauling of lime/limestone).

An SCR or equivalent NO_x control device must achieve an emission rate of 0.080 lb/MMBtu or better and be in operation by December 31, 2012. APM control device must achieve an emission rate of 0.030 lb/MMBtu within 90 days after entry of the consent decree. Additionally, a PM CEMS must be installed on Cooper Unit 1.

4.1.2 Case A: Performance / Capital Cost / O & M Cost Estimate

Table 4-1 provides performance, capital cost, and Operation and Maintenance estimates for Case A for scenarios utilizing both a coal with average sulfur content (2.2% by weight) and a coal with a high sulfur content (4.2% by weight).

Table 4-1

Case A – Cooper Unit 2 SDA

		Avg Sulfur	High Sulfur	
PERFORMANCE	Total Nameplate Capacity	220	220	(MW)
	Plant Net Heat Rate	10,240	10,240	(Btu/kWh)
CAPITAL COST	NO_x emissions controls (SCR)	$59,455,761	$59,445,367	(2007$)
	SO_2 emission controls (SDA)	$167,506,185	$214,361,293	(2007$)
	Stack breakout - included with SDA	$17,255,000	$17,439,000	(2007$)
	Booster Fan breakout - incl. w/SDA	$5,144,891	$5,241,293	(2007$)
	PM emission controls - Fabric Filter	$65,732,511	$70,128,495	(2007$)
	Total Capital Requirement (TCR)	$292,694,457	$343,935,155	(2007$)
	Total Project Cost (per Total Capacity)	$1,330	$1,563	(2007$/kW)
O & M COSTS	Total Fixed O&M - Existing Plant	2.21	2.21	(2007$/MWh)
	Variable O&M - Exisitng Plant	11.32	11.32	(2007$/MWh)
	Fuel - Existing Plant	23.58	23.58	(2007$/MWh)
	NO_x emissions controls (SCR)	$2,599,121	$2,598,755	(2007$/yr)
	SO_2 emission controls (SDA)	$12,524,178	$23,372,773	(2007$/yr)
	Stack breakout - included with SDA	$166,142	$167,913	(2007$/yr)
	Booster Fan breakout - incl. w/SDA	$35,279	$35,940	(2007$/yr)
	PM emission controls - Fabric Filter	$1,302,836	$1,371,974	(2007$/yr)
	Total O&M Costs for Pollution Control	$16,426,135	$27,343,502	(2007$/yr)

4.2 CASE B: COOPER UNIT 2 WET SCRUBBER

Case B is identical to Case A except for the fact that a wet scrubber (WFGD) is installed rather than a dry scrubber (SDA). Like Case A, the SCR must be in operation by December 31, 2012 and the WFGD must be in operation by August 30, 2012. Cooper Unit 1 continues to operate as before and a continuous emissions monitoring system is added to both units. All four Dale units continue to operate as usual with any retirement decisions being deferred until the next major overhaul.

4.2.1 Case B: Environmental Analysis

If EKPC decides to retrofit Cooper Unit 2 with a wet scrubber, notification must be made to EPA by December 21, 2009. The wet scrubber must achieve an emission rate of 0.100 lb SO_2/MMBtu (30-day rolling average) or achieve at least 95% reduction in SO_2 emissions. The scrubber must be operation by June 30, 2012. Compliance must be demonstrated in part through an SO_2 CEMS. Additionally, the system-wide SO_2 12-month rolling tonnage limits shown in Table 2.4-5 must be met.

This option would likely require permitting for the new particulate emissions associated with the scrubber (material transfer and hauling of lime/limestone) since the PSD major source threshold is only 15 tpy.

An SCR or equivalent NO_x control device must achieve an emission rate of 0.080 lb/MMBtu or better and be in operation by December 31, 2012, APM control device must achieve an emission rate of 0.030 lb/MMBtu within 90 days after entry of the consent decree. Additionally, a PM CEMS must be installed on Cooper Unit 1.

4.2.2 Case B: Performance / Capital Cost / O & M Estimate

Table 4-2 provides performance, capital cost, and Operation and Maintenance estimates for Case B for scenarios utilizing coal with average sulfur content (2.2% by weight) and coal with a high sulfur content (4.2% by weight).

Table 4-2

Case B – Cooper Unit 2 WFGD

		Avg Sulfur	High Sulfur	
PERFORMANCE	Total Nameplate Capacity	220	220	(MW)
	Turbine Cycle Heat Rate	10,240	10,240	(Btu/kWh)
CAPITAL COST	NO_x emissions controls (SCR)	$59,455,761	$59,445,266	(2007$)
	SO_2 emission controls (WFGD)	$247,704,308	$257,912,941	(2007$)
	Stack breakout - included with WFGD	$20,490,000	$20,588,000	(2007$)
	Booster Fan breakout - incl. w/WFGD	$6,921,548	$6,919,930	(2007$)
	PM emission controls - Fabric Filter	$689,370	$689,370	(2007$)
	Total Capital Requirement (TCR)	$307,849,439	$318,047,578	(2007$)
	Total Project Cost (per Total Capacity)	$1,399	$1,446	(2007$/kW)
O & M COSTS	Total Fixed O&M - Existing Plant	2.21	2.21	(2007$/MWh)
	Variable O&M - Exisitng Plant	11.32	11.32	(2007$/MWh)
	Fuel - Existing Plant	23.58	23.58	(2007$/MWh)
	NO_x emissions controls (SCR)	$2,599,121	$2,598,749	(2007$/yr)
	SO_2 emission controls (WFGD)	$9,895,843	$13,177,708	(2007$/yr)
	Stack breakout - included with WFGD	$246,372	$247,551	(2007$/yr)
	Booster Fan breakout - incl. w/WFGD	$71,193	$71,176	(2007$/yr)
	PM emission controls - Fabric Filter	$955,834	$947,369	(2007$/yr)
	Total O&M Costs for Pollution Control	$13,450,798	$16,723,826	(2007$/yr)

4.3 CASE C: COOPER UNITS 1 & 2 WET SCRUBBER

In Case C a wet scrubber (WFGD) is sized and added to support both Cooper Unit 1 and Cooper Unit 2. In this way Cooper Unit 1 and Cooper Unit 2 basically operate as a single unit which means that the total rating of this "combined" system is about 340 MW. Again, the SCR must be in operation by December 31, 2012 and the WFGD must be in operation by August 30, 2012. A continuous emission monitoring system is added to both units. All four Dale Units continue to operate as usual with any retirement decisions being deferred until the next major overhaul.

4.3.1 Case C: Environmental Analysis

If EKPC decides to retrofit both Cooper Unit 1 and Cooper Unit 2 with a wet scrubber, notification must be made to EPA by December 21, 2009. The wet scrubber must achieve an emission rate of 0.100 lb SO_2/MMBtu (30-day rolling average) or achieve at least 95% reduction in SO_2 emissions. Obtaining the required control efficiency will be easier with a wet scrubber than a dry scrubber. The scrubber must be operation by June 30, 2012. Compliance must be demonstrated in part through an SO_2 CEMS. Additionally, the system-wide SO_2 12-month rolling tonnage limits shown in Table 2.4-5 must be met.

Since controlling Cooper Unit 1 as well as Cooper Unit 2 is beyond the scope of the consent order, the emissions reductions from the control of Cooper Unit 1 would be available as allowances for other units in the EKPC system or to be sold per paragraph 77d of the consent decree.

4.3.2 Case C: Performance / Capital Cost / O&M Estimate

Table 4-3 provides performance, capital cost, and Operation and Maintenance estimates for Case C for scenarios utilizing coal with average sulfur content (2.2% by weight) and coal with a high sulfur content (4.2% by weight).

Table 4-3

Case C – Cooper Units 1 & 2 WFGD

		Avg Sulfur	High Sulfur	
PERFORMANCE	Total Nameplate Capacity	341	341	(MW)
	Turbine Cycle Heat Rate	10,240	10,240	(Btu/kWh)
CAPITAL COST	NO_x emissions controls (SCR)	$97,550,617	$97,533,732	(2007$)
	SO_2 emission controls (WFGD)	$291,027,851	$304,943,632	(2007$)
	Stack breakout - included with WFGD	$26,080,406	$26,205,223	(2007$)
	Booster Fan breakout - incl. w/WFGD	$9,146,525	$9,144,387	(2007$)
	PM emission controls - Fabric Filter	$95,507,151	$95,385,300	(2007$)
	Total Capital Requirement (TCR)	$484,085,619	$497,862,664	(2007$)
	Total Project Cost (per Total Capacity)	$1,420	$1,460	(2007$/kW)
O & M COSTS	Total Fixed O&M - Existing Plant	2.21	2.21	(2007$/MWh)
	Variable O&M - Exisitng Plant	11.32	11.32	(2007$/MWh)
	Fuel - Existing Plant	23.58	23.58	(2007$/MWh)
	NO_x emissions controls (SCR)	$4,027,521	$4,026,949	(2007$/yr)
	SO_2 emission controls (WFGD)	$13,276,629	$18,185,027	(2007$/yr)
	Stack breakout - included with WFGD	$288,891	$290,273	(2007$/yr)
	Booster Fan breakout - incl. w/WFGD	$94,079	$94,057	(2007$/yr)
	PM emission controls - Fabric Filter	$1,355,912	$1,343,208	(2007$/yr)
	Total O&M Costs for Pollution Control	$18,660,062	$23,555,184	(2007$/yr)

4.4 CASE D: COOPER UNIT 2 REPOWER WITH CFB

Case D assumes that Cooper Unit 2 is repowered with a like-sized (250 MW) Combustion Fluidized Bed (CFB) unit. All four Dale units continue to operate as usual with any retirement decisions being deferred until the next major overhaul.

4.4.1 Case D: Environmental Analysis

If EKPC decides to repower Cooper Unit 2 with a CFB, a Prevention of Significant Deterioration (PSD) permit will be required, including Best Available Control Technology (BACT) determination and dispersion modeling. BACT would be set more stringent than 0.100 lb SO_2/MMBtu or 95% reduction. The decrease of $SO_2$from 0.100 lb SO_2/MMBtu or 95% to the lower BACT level can be sold or transferred per paragraph 77c of the consent decree, after meeting the system-wide SO_2 requirements shown in Table 2.3-5.

Additionally, a new coal-fired boiler would likely be subject to lawsuits and delays from intervener groups. A new CFB would probably be subject to more public scrutiny than retrofitting the existing unit even though repowering would likely result in a greater decrease in overall emissions.

Additionally, a PM CEMS must be installed on Cooper Unit 1.

4.4.2 Case D: Performance / Capital Cost / O&M Estimate

Table 4-4 provides performance, capital cost, and Operation and Maintenance estimates for Case D utilizing fuel for the CFB.

Table 4-4

Case D – Cooper Unit 2 Repower with CFB

PERFORMANCE	Total Project Capacity	250	(MW)
	Heat Rate - Full Load without Duct Firing	10,240	(Btu/kWh)
CAPITAL COST	Equipment Cost (1)	$200,000,000	(2007$)
	Construction / Erection Costs	$50,000,000	(2007$)
	SNCR / Baghouse (2)	$0	(2007$)
	Civil / Electrical / Other BOP	$24,000,000	(2007$)
	Engineering / Project Management	$45,000,000	(2007$)
	Coal / Limestone Handling / Storage (3)	$17,000,000	(2007$)
	Project Indirects & Owner's Cost	$55,000,000	(2007$)
	Total Cost w/out IDC	$391,000,000	(2007$)
	Interest During Construction	$27,370,000	(2007$)
	Contingency	$62,755,500	(2007$)
	Total Project Cost	$481,125,500	(2007$)
	Total Project Cost (per Total Capacity)	$1,925	(2007$/kW)
O & M COSTS	Total Fixed O&M	2.21	(2007$/MWh)
	Variable O&M	~~11.60~~ 7	(2007$/MWh)

(1) This includes the CFB Boiler, boiler steel, coal mills, SNCR, Flash dryer, Baghouse, Limestone system, Limestone silos in boiler house, coal silos in boiler house (from Alstrom)

(2) SNCR and Baghouse are included in Equipment Cost

(3) Silos are included in Equipment Cost

4.5 CASE E: RETIRE DALE 1-4

In this case all four units at Dale are retired. This must be accomplished on or before December 31, 2012 to comply with the Cnsent Decree. Cooper Units 1 and 2 continue to operate as usual with continuous emissions monitoring devices added to both units. The only capital costs required in this case are for renumeration costs which are presented in Section 2.6 of this report. It is assumed in the economic analysis that the capacity and energy from the Dale Units will be made up of power purchases from the spot market.

4.5.1 Case E: Environmental Analysis

If EKPC decides to retire Dale Units 1, 2, 3, and 4, no environmental permits would be required. Since retiring all four (4) units is beyond the scope of the consent order, the emissions reductions from Dale Units 1 and 2 would be available as allowances for other units in the EKPC system or to be sold per paragraph 77d of the consent decree.

Additionally, a PM CEMS must be installed on Cooper Unit 1.

4.5.2 Case E: Performance / Capital Cost / O&M Estimate

Table 4-5 provides data for Case E cases which requires capital costs for site remediation which all replacement capacity and energy being purchased.

Table 4-5

Case E – Retire Dale Units 1-4

PERFORMANCE	Total Project Capacity	N/A	(MW)
	New Project Capacity	N/A	(MW)
	Heat Rate - Full Load without Duct Firing	N/A	(Btu/kWh)
	Heat Rate - 75% Load	N/A	(Btu/kWh)
CAPITAL COST	Capital Cost	$0	(2007$)
	Project Indirects & Owner's Cost	$0	(2007$)
	Site Renumeration Costs	$9,308,400	(2007$)
	Total Cost w/out IDC	$9,308,400	(2007$)
	Interest During Construction	$0	(2007$)
	Total Project Cost	$9,308,400	(2007$)
O & M COSTS	Fixed O&M (excl. property tax/insurance)	0	(2007$/kW-yr)
	Variable O&M (Excl. Major Maintenance)	0	(2007$/MWh)

4.6 CASE F: REPOWER DALE UNITS 3&4 WITH 7FA COMBINED CYCLE

Case F assumes repowering of Dale Units 3 and 4 is performed per the Consent Decree with a two 1 on 1 General Electric 7FA combustion turbines operating in combined cycle mode. This will add approximately 330 MW to the existing 150 MW making the new capacity about 480 MW without any duct firing. The "new" existing steam turbines would be incorporated. Dale Units 1 and 2 and Cooper Units 1 and 2 would all continue to operate as usual.

4.6.1 Case F: Environmental Analysis

If EKPC decides to repower Dale Units 3 and 4 with a 7FA Combined Cycle, a PSD permit will be required, including BACT determination and dispersion modeling. BACT likely be 3 ppm NO_x, installation of a SCR, and use of pipeline quality natural gas. However, a combined cycle would be less likely to be subject to lawsuits and delays from intervener groups than a coal-fired unit.

Additionally, a PM CEMS must be installed on Cooper Unit 1 and both Cooper Units 1 and 2 must comply with the following:

- NO_x CEMS
- SO_2 CEMS
- Annual PM stack test
- PM control device to achieve 0.030 lb/MMBtu emission rate
- Low NO_x burners
- System-wide NO_x and SO_2 limits

4.6.2 Case F: Performance / Capital Cost / O&M Estimate

Table 4-6 provides performance, capital cost, and Operation and Maintenance estimates for Case F utilizing natural gas.

Table 4-6

Case F – Dale Units 3 & 4 Repower (2-1x1 CCGT 7FA)

PERFORMANCE	Total Project Capacity	480	(MW)
	New Project Capacity	330	(MW)
	Heat Rate - Full Load without Duct Firing (HHV)	7,450	(Btu/kWh)
	Heat Rate - 75% Load	7,823	(Btu/kWh)
	Heat Rate - 50% Load	8,493	(Btu/kWh)
CAPITAL COST	Capital Cost	$245,600,000	(2007$)
	Project Indirects & Owner's Cost	$80,900,000	(2007$)
	Site Renumeration Costs	$2,717,670	(2007$)
	Total Cost w/out IDC	$329,217,670	(2007$)
	Interest During Construction	$22,100,000	(2007$)
	Total Project Cost	$351,317,670	(2007$)
	Total Project Cost (per Total Capacity)	732	(2007$/kW)
O & M COST	Fixed O&M (excl. property tax/insurance)	$3,600,000	(2007$/yr)
	Variable O&M (Excl. Major Maintenance)	4.1	(2007$/MWh)
	GT Major Maintenance, Cost per Hour	$500	(2007$/hour)

4.7 CASE G: REPOWER DALE UNITS 3&4 WITH 7EA COMBINED CYCLE

Case G assumes repowering of Dale Units 3 and 4 is performed per the Consent Decree with a two 1 on 1 General Electric 7EA combustion turbines operating in combined cycle mode. This will add approximately 170 MW to the existing 150 MW making the new capacity about 320 MW without any duct firing. The "new" existing steam turbines would be incorporated. Dale Units 1 and 2 and Cooper Units 1 and 2 would all continue to operate as usual.

4.7.1 Case G: Environmental Analysis

If EKPC decides to repower Dale Units 3 and 4 with a 7FA Combined Cycle, a PSD permit will be required, including BACT determination and dispersion modeling. BACT likely be 3 ppm NO_x, installation of a SCR, and use of pipeline quality natural gas. However, a combined cycle would be less likely to be subject to lawsuits and delays from intervener groups than a coal-fired unit.

Additionally, a PM CEMS must be installed on Cooper Unit 1 and both Cooper Units 1 and 2 must comply with the following:

- NO_x CEMS
- SO_2 CEMS
- Annual PM stack test
- PM control device to achieve 0.030 lb/MMBtu emission rate
- Low NO_x burners
- System-wide NO_x and SO_2 limits

4.7.2 Case G: Performance / Capital Cost / O&M Estimate

Table 4-7 provides performance, capital cost, and Operation and Maintenance estimates for Case G utilizing natural gas.

Table 4-7

Case G – Dale Units 3 & 4 Repower (2-1x1 CCGT 7EA)

PERFORMANCE	Total Project Capacity	300	(MW)
	New Project Capacity	170	(MW)
	Heat Rate - Full Load with Duct Firing	8,500	(Btu/kWh)
CAPITAL COST	Capital Cost	$202,400,000	(2007$)
	Project Indirects & Owner's Cost	$76,500,000	(2007$)
	Site Retirement Costs	$2,717,670	(2007$)
	Total Cost w/o IDC	$281,617,670	(2007$)
	Interest During Construction	$20,300,000	($)
	Total Project Cost	$301,917,670	(2007$)
	Total Project Cost (per Total Capacity)	$1,006	(2007$/kW)
O&M COSTS	Fixed O&M (excl. property tax/insurance)	$3,600,000	(2007$/yr)
	Variable O&M (Excl. Major Maintenance)	4.2	(2007$/MWh)
	GT Major Maintenance, Cost per Hour	$200	(2007$/hour)
	GT Major Maintenance, Cost per Start	$6,000	(2007$/start)

4.8 CASE H: REPOWER DALE UNITS 3&4 WITH CFB

Case H assumes repowering of Dale Units 3 and 4 is performed per the Consent Decree with a 150 MW CFB unit. This keeps the output of the Dale station at about the same level as before the repowering. The "new" existing steam turbines would be incorporated. Dale Units 1 and 2 and Cooper Units 1 and 2 would all continue to operate as usual.

4.8.1 Case H: Environmental Analysis

If EKPC decides to repower Dale Units 3 and 4 with a CFB, a Prevention of Significant Deterioration (PSD) permit will be required, including Best Available Control Technology (BACT) determination and dispersion modeling. BACT would be set more stringent than 0.100 lb SO_2/MMBtu or 95% reduction. The decrease of $SO_2$from 0.100 lb SO_2/MMBtu or 95% to the lower BACT level can be sold or transferred per paragraph 77c of the consent decree, after meeting the system-wide SO_2 requirements shown in Table 2.3-5.

Additionally, a new coal-fired boiler would likely be subject to lawsuits and delays from intervener groups. A new CFB would probably be subject to more public scrutiny than retrofitting the existing unit even though repowering would likely result in a greater decrease in overall emissions.

Additionally, a PM CEMS must be installed on Cooper Unit 1 and both Cooper Units 1 and 2 must comply with the following:

- NO_x CEMS
- SO_2 CEMS
- Annual PM stack test
- PM control device to achieve 0.030 lb/MMBtu emission rate
- Low NO_x burners
- System-wide NO_x and SO_2 limits

4.8.2 Case H: Performance / Capital Cost / O&M Estimate

Table 4-8 provides performance, capital cost, and Operation and Maintenance estimates for Case H utilizing natural gas.

Table 4-8

Case H – Dale Units 3 & 4 Repower with CFB

PERFORMANCE	Total Nameplate Capacity	144	(MW)
	Plant Heat Rate	11,038	(Btu/kWh)
CAPITAL COST	Capital Cost (1)	$85,000,000	(2007$)
	Construction / Erection Costs	$31,000,000	(2007$)
	SNCR / Baghouse	$25,000,000	(2007$)
	Civil / Electrical / Other BOP	$13,500,000	(2007$)
	Engineering / Project Management	$35,000,000	(2007$)
	Coal / Limestone Handling / Storage	$24,000,000	(2007$)
	Project Indirects & Owner's Cost	$33,000,000	(2007$)
	Site Renumeration Costs	$6,082,800	(2007$)
	Total Cost w/out IDC	$252,582,800	(2007$)
	Interest During Construction	$17,680,796	(2007$)
	Contingency	$40,539,539	(2007$)
	Total Project Cost	$310,803,135	(2007$)
	Total Project Cost (per Total Capacity)	$2,158	(2007$/kW)
O & M COSTS	Total Fixed O&M	3.00	(2007$/MWh)
	Variable O&M (Excl. Major Maintenance)	~~18.16~~ 7	(2007$/MWh)

1) The scope is boiler design, engineering and supply with air fans and silo inlet to ID fan outlet. This design would include an allowance for adding some type of scrubber and a baghouse on the backend (from Foster Wheeler).

5.0 ECONOMIC RESULTS

5.1 LEVELIZED BUSBAR ANALYSIS

As was discussed in the assumptions section of this Report an evaluation of the economic merits of each case was performed using a customized bus-bar model that was developed specifically for this study. The summary results of this analysis are shown in Tables 5-1 and 5-2 and in Figure 5-1. Also provided in Appendix F are key model output tables for each case studied.

In considering the results of the economic analysis, it must again be stressed that these results can only serve as a guide to more detailed study that takes into consideration each unit's role within the overall EKPC system and planning environment.

The results presented were arrived at through the explicit consideration of a wide variety of variables that pertained to each unit at the Dale Station and the Cooper Station. The operation of all units was considered in each case studied, though each unit's particular operation was not treated as a function of or related to the operation of the other units.

Specific variables that were considered for each unit for each case included:

- Rated capacity
- Heat rate
- Capacity factor
- Availability (retirement or forced outage)
- Type of fuel burned
- Price of fuel burned
- Fixed O&M costs
- Variable O&M costs
- Major maintenance costs
- Unit down time during the transition from the current plant/unit configuration to operations to the new configuration as specified by each case studied

Other important factors that were explicitly considered include:

- Price of medium sulfur and high sulfur coal that would be consumed by each unit
- Price of natural gas for Case F and Case G that called for the installation of combined cycle units at Dale Unit 3 and Unit 4.

- Cost to replace energy not provided by a specific unit. The cost of market purchases included: (1) the projected LMP price at the EKPC node, (2) a market capacity cost, (3) a cost for Network Integrated Transmission Service (NITS), and the cost of an "energy management" fee (assumed to be 15 percent).

As can be seen from Tables 5-1 and 5-2 and Figure 5-1, the overall lowest costs were estimated for Cases E, D, and H and the overall highest costs were estimated for Cases A, B, and C. Case E consisted of the retirement of the Dale units, and it was assumed that this reduction in generation would be made up with market purchases. One reason that Case E proved to be of relatively lower cost compared to other cases was the fact that if retired, per the Consent Decree, EKPC would not have to take any other action involving substantial capital outlays. Cases H and D benefited from a combination of factors including relatively lower fuel costs and fixed O&M costs. Cases F and G were of higher costs primarily due the high cost of natural gas to fire the combined cycle units. Cases A, B and C were estimated to be at the higher end of the cost spectrum due to relatively higher capital costs and relatively higher fixed O&M costs.

These results varied somewhat depending upon the capacity factor assumed and the fuel type specified. However, notwithstanding such variations, Cases D, E, and H proved to be consistently of lower cost and Cases A, B, and C proved to be consistently of higher cost.

Table 5-1
Summary of Case Cost Breakdown

Busbar Analysis Results		Excluding Carbon Tax		Including Carbon Tax	
		Total All Costs (2) and/or Market Purchases $/yr x 1000	Total All Costs and/or Market Purchases $/MWh	Total All Costs and/or Market Purchases $/yr x 1000	Total All Costs and/or Market Purchases $/MWh
Cases (1)		EAC(3)	EAC(3)	EAC(3)	EAC(3)
Case H	Repower Dale 3 & 4 with CFB	$218,823	$71.27	$255,646	$83.29
Case D	Repower Cooper 2 with CFB	$237,070	$72.88	$274,314	$84.25
Case F	Repower Dale 3 & 4 Combined Cycle (2-1x1 7FA)	$346,224	$73.64	$386,490	$81.66
Case G	Repower Dale 3 & 4 Combined Cycle (2-1x1 7EA)	$289,664	$75.60	$324,323	$84.33
Case B-1	Cooper 2 Wet Scrubber - Avg Sulfur	$237,769	$76.72	273,025	$88.10
Case B-2	Cooper 2 Wet Scrubber - High Sulfur	$239,142	$77.16	274,398	$88.54
Case A-1	Cooper 2 Dry Scrubber - Avg Sulfur	$240,430	$77.58	275,686	$88.96
Case C-2	Cooper 1 & 2 Wet Scrubber - High Sulfur	$244,809	$78.34	280,397	$89.72
Case C-1	Cooper 1 & 2 Wet Scrubber - Avg Sulfur	$246,048	$78.74	281,635	$90.11
Case A-2	Cooper 2 Dry Scrubber - High Sulfur	$253,347	$81.75	288,603	$93.12

Note (1) Case results sorted by $/MWh, No Carbon Tax

Note (2) "Total All Costs" Include: Capital, Fuel, Fixed O&M, Variable O&M, Major Maintenace at 70% Capacity Factor

Note (3) "EAC" = "Equivalent Annual Cost" for period 2007 thru 2035

Figure 5-1

EAC ($/MWh) vs. Capacity Factor

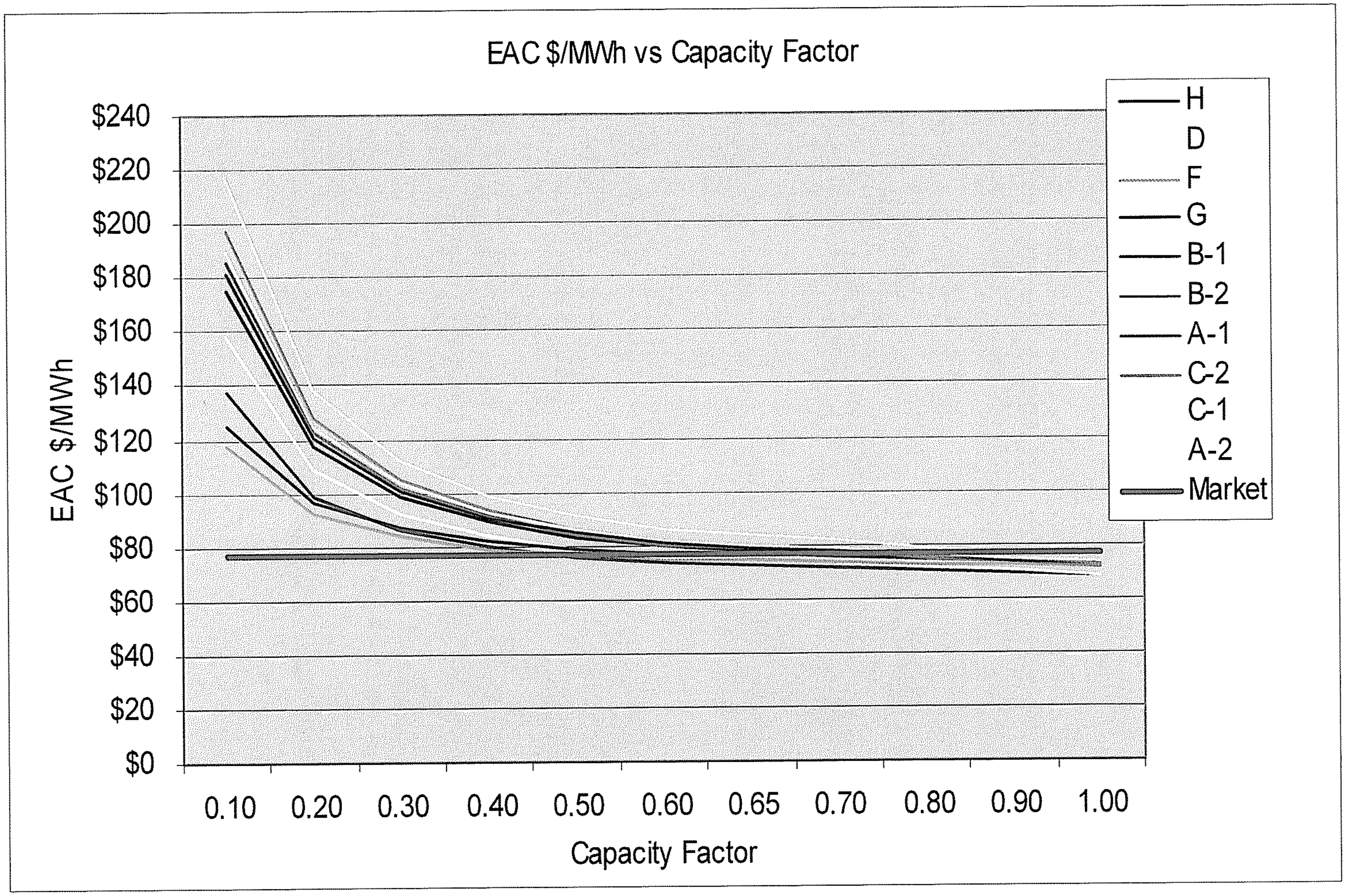


Table 5-2

Busbar Results Analysis

	Market Purchases $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh	Total Costs $/MWh
Capacity Factor		0.10	0.20	0.30	0.40	0.50	0.60	0.65	0.70	0.80	0.90	1.00
	EAC	EAC	EAC	EAC	EAC	EAC	EAC	EAC	EAC	EAC	EAC	EAC
Case H	$76	$136.82	$98.59	$85.84	$79.47	$75.64	$73.10	$72.12	$71.27	$69.91	$68.85	$68.00
Case D	$76	$158.63	$108.61	$91.94	$83.60	$78.60	$75.26	$73.98	$72.88	$71.09	$69.70	$68.59
Case F	$76	$117.38	$91.87	$83.36	$79.11	$76.55	$74.85	$74.20	$73.64	$72.73	$72.02	$71.45
Case G	$76	$124.72	$96.07	$86.52	$81.74	$78.88	$76.97	$76.23	$75.60	$74.58	$73.78	$73.15
Case B-1	$76	$175.45	$117.86	$98.66	$89.06	$83.30	$79.46	$77.99	$76.72	$74.66	$73.07	$71.79
Case B-2	$76	$185.11	$122.14	$101.15	$90.66	$84.36	$80.16	$78.55	$77.16	$74.92	$73.17	$71.77
Case A-1	$76	$181.46	$120.86	$100.66	$90.57	$84.51	$80.47	$78.91	$77.58	$75.42	$73.73	$72.39
Case C-2	$76	$197.30	$127.91	$104.78	$93.21	$86.27	$81.64	$79.86	$78.34	$75.86	$73.93	$72.39
Case C-1	$76	$190.06	$125.12	$103.47	$92.65	$86.16	$81.83	$80.16	$78.74	$76.42	$74.61	$73.17
Case A-2	$76	$217.20	$138.19	$111.85	$98.68	$90.78	$85.51	$83.48	$81.75	$78.93	$76.73	$74.98

* * * * *

APPENDIX A –Transmission Analysis for Dale Station (Prepared by EKPC)

DALE STATION TRANSMISSION ANALYSIS

A power flow analysis has been performed to identify transmission problems and a conceptual solution for two generation scenarios at the W.C. Dale Power Station. The two scenarios evaluated were:

1. 650 MW of total generation output
2. 0 MW of total generation output

The power flow analysis was performed using 2011 Summer and 2011/12 Winter base case models developed and maintained by EKPC's Transmission Planning Department. These models were developed from the NERC MMWG 2006 Series models, with a detailed representation of the EKPC and E-ON U.S. systems inserted. Single-contingency analysis was performed on the two generation scenario cases to identify problems created by the new generation levels at Dale Station.

Scenario 1: 650 MW Dale Station Output
An equivalent 650 MW generating unit was modeled connected to the Dale 138 kV bus. The thermal problems identified are listed in Table 1A.

Table 1A
Thermal Overloads with 650 MW of Total Generation Output at Dale Station

Peak Season	Limiting Facility	Owner	Worst-Case Contingency	Worst-Case Dispatch	Rating	MVA Flow	% Overload
2011 Summer	Dale-Three Forks Jct. 138 kV Line	EKPC	Avon-Boonesboro North-Dale 138 kV Line (EKPC)	Brown #3 off	220	381.1	173.2%
2011 Summer	Three Forks Jct.-Fawkes EKPC 138 kV Line	EKPC	Avon-Boonesboro North-Dale 138 kV Line (EKPC)	Brown #3 off	220	366.5	166.6%
2011 Summer	Dale 138/69 kV Transformer	EKPC	None	Base	78	109.2	140.0%
2011/12 Winter	Dale-Three Forks Jct. 138 kV Line	EKPC	Avon-Boonesboro North-Dale 138 kV Line (EKPC)	Brown #3 off	283	394.8	139.5%
2011 Summer	Dale-Three Forks Jct. 138 kV Line	EKPC	None	Base	179	246.5	137.7%
2011/12 Winter	Three Forks Jct.-Fawkes EKPC 138 kV Line	EKPC	Avon-Boonesboro North-Dale 138 kV Line (EKPC)	Brown #3 off	283	381.1	134.7%
2011 Summer	Three Forks Jct.-Fawkes EKPC 138 kV	EKPC	None	Base	179	231.9	129.6%

Prepared by:
EKPC Transmission Planning 11/5/2007

Table 1A Thermal Overloads with 650 MW of Total Generation Output at Dale Station							
Peak Season	Limiting Facility	Owner	Worst-Case Contingency	Worst-Case Dispatch	Rating	MVA Flow	% Overload
	Line						
2011 Summer	Dale 138/69 kV Transformer	EKPC	JK Smith-Powell County 138 kV Line (EKPC)	Brown #3 off	111	137.6	124.0%
2011 Summer	Winchester South-Winchester 69 kV Line	E-ON	Fawkes-Clark County 138 kV Line (EON)	Spurlock #2 off	110	133.6	121.5%
2011 Summer	Dale-Boonesboro North 138 kV Line	EKPC	North Clark-Avon 345 kV Line and or Avon 345/138 kV Transformer (EKPC)	Brown #3 off	300	361.4	120.5%
2011/12 Winter	Dale 138/69 kV Transformer	EKPC	None	Base	111	130	117.1%
2011/12 Winter	Dale 138/69 kV Transformer	EKPC	JK Smith-Powell County 138 kV Line (EKPC)	Cooper #2 off	141	162.6	115.3%
2011/12 Winter	Dale-Three Forks Jct. 138 kV Line	EKPC	None	Base	258	293.1	113.6%
2011 Summer	Alcalde-Elihu 161 kV Line	E-ON	Wolf Creek-Russell County Jct. 161 kV Line (TVA-EKPC)	Cooper #2 off	252	285.4	113.3%
2011 Summer	Boonesboro North-Winchester Water Works 69 kV Line	E-ON	Fawkes-Clark County 138 kV Line (EON)	Spurlock #2 off	150	169.7	113.1%
2011/12 Winter	Three Forks Jct.-Fawkes 138 kV Line	EKPC	None	Base	258	282.8	109.6%
2011 Summer	Boonesboro North-Winchester Water Works 69 kV Line	E-ON	None	Base	120	126.9	105.8%
2011 Summer	Fawkes EKPC-Fawkes EON 138 kV Line	EKPC-E-ON	Fawkes EKPC-Fawkes Tap 138 kV Line (EKPC-EON)	Brown #3 off	287	303.3	105.7%
2011 Summer	Fawkes EKPC-Fawkes Tap 138 kV Line	EKPC-E-ON	Fawkes EKPC-Fawkes EON 138 kV Line (EKPC-EON)	Brown #3 off	287	301.6	105.1%
2011 Summer	Winchester Water Works-	E-ON	Fawkes-Clark County 138 kV	Spurlock #2 off	150	154.3	102.9%

Prepared by:
EKPC Transmission Planning 11/5/2007

Table 1A Thermal Overloads with 650 MW of Total Generation Output at Dale Station							
Peak Season	*Limiting Facility*	Owner	Worst-Case Contingency	Worst-Case Dispatch	Rating	MVA Flow	% Overload
	Boone Avenue 69 kV Line		Line (EON)				
2011 Summer	Clark County 138-69 kV Transformer	E-ON	Avon-Boonesboro North-Dale 138 kV Line (EKPC)	Brown #3 off	107	109.8	102.6%

These results indicate that the following facilities would be overloaded with a 650 MW output at Dale Station:

- Dale-Three Forks Jct.-Fawkes 138 kV Line
- Dale 138/69 kV Transformer
- Alcalde-Elihu 161 kV Line
- Boonesboro North-Winchester Water Works-Boone Avenue 69 kV Line
- Clark County 138/69 kV Transformer
- Winchester South-Winchester 69 kV Line
- Dale-Boonesboro North 138 kV Line
- Fawkes EKPC-Fawkes EON 138 kV Line
- Fawkes EKPC-Fawkes Tap 138 kV Line

The overloads of the first five facilities listed above are significant overloads involving major limitations (line conductor or autotransformer capacity limits). The remaining four facility limitations are less significant, involving terminal limitations and/or conductor clearances.

The voltage violations identified are listed in Table 1B.

Table 1B Voltage Violations with 650 MW of Total Generation Output at Dale Station						
Peak Season	Critical Bus	Owner	Worst-Case Contingency	Worst-Case Dispatch	Minimum Voltage Requirement	Voltage Value from Powerflow
2011 Summer	Hunt #1 25 kV	EKPC	Dale 138-69 kV Transformer (EKPC)	Brown #3 off	92.5%	89.7%
2011/12 Winter	Perryville 12.5 kV	EKPC	North Springfield-Mackville 69 kV Line (EKPC)	Base	92.5%	90.3%
2011/12 Winter	Asahi 12.5 kV	EKPC	Norwood Jct.-Shopville 69 kV Line (EKPC)	Base	92.5%	90.8%
2011/12 Winter	Perryville 12.5 kV	EKPC	None	Base	95.5%	95.0%
2011/12	Hardwicks	EKPC	Powell County-	Cooper #2	92.5%	92.4%

Prepared by:
EKPC Transmission Planning 11/5/2007

Table 1B Voltage Violations with 650 MW of Total Generation Output at Dale Station						
Peak Season	Critical Bus	Owner	Worst-Case Contingency	Worst-Case Dispatch	Minimum Voltage Requirement	Voltage Value from Powerflow
Winter	Creek 12.5 kV		Stanton 69 kV Line (EKPC)	off		

One voltage problem was identified without any contingencies. Additional low voltage problems for four different contingencies were identified for this scenario.

The transmission system expansion plan identified to mitigate the problems identified in Tables 1A and 1B is listed in Table 1C. This plan represents a reasonable and viable solution to the problems created by the generation additions at Dale Station. A more detailed, thorough analysis should be performed if this generation scenario at Dale is pursued further to identify alternative plans and to confirm that this plan is the preferred alternative.

Table 1C Transmission Expansion Plan to Address System Problems for 650 MW Generation Output at Dale Station	
Project Description	Estimated Cost in millions ($2007)
Construct 11.6 miles of 138 kV line from Dale Station to E-ON's Brown Plant-Fawkes 138 kV line near EKPC's Newby Substation.	5.2
Construct a 138/69 kV, 100 MVA Substation at Newby, including the facilities needed to connect the Dale-Newby 138 kV line to E-ON's Brown Plant-Fawkes 138 kV line.	3.9
Re-conductor the Dale-Three Forks Jct.-Fawkes 138 kV line using 556.5 MCM ACSS conductor (8.21 miles)	1.9
Replace the Dale 138/69 kV, 82.5 MVA transformer with a 100 MVA transformer	1.5
Loop EKPC's Dale-Avon 138 kV line through E-ON's Boonesboro North Substation and install a 2nd Boonesboro North 138/69 kV, 100 MVA transformer.	3.0
Re-conductor E-ON's Alcalde-Elihu 161 kV line using 795 MCM ACSR conductor (2.95 miles)	0.8
Reconductor E-ON's Boonesboro North-Winchester 69 kV line using 1590 MCM ACSR conductor (7.73 miles), and upgrade the terminal equipment associated with this line.	2.1
Total Cost	$18.4

Scenario 2: 0 MW Dale Station Output

All Dale Station generating units were turned off in the power flow models. No thermal problems were identified for this scenario. Several voltage problems were identified, and are listed in Table 2A.

Table 2A
Voltage Violations with 00 MW of Total Generation Output at Dale Station

Peak Season	Critical Bus	Owner	Worst-Case Contingency	Worst-Case Dispatch	Minimum Voltage Requirement	Voltage Value from Powerflow
2011/12 Winter	Perryville 12.5 kV	EKPC	North Springfield-Mackville 69 kV Line (EKPC)	JK Smith CFB #1 off	92.5%	82.8%
2011 Summer	Stanton 12.5 kV	EKPC	Powell County-Stanton 69 kV Line (EKPC)	JK Smith CFB #1 off	92.5%	86.0%
2011/12 Winter	Hardwicks Creek 12.5 kV	EKPC	Powell County-Stanton 69 kV Line (EKPC)	JK Smith CFB #1 off	92.5%	87.0%
2011 Summer	Perryville 12.5 kV	EKPC	North Springfield-Mackville 69 kV Line (EKPC)	JK Smith CFB #1 off	92.5%	89.4%
2011/12 Winter	West Liberty 12.5 kV	EKPC	Skaggs-Crockett 69 kV Line (EKPC)	JK Smith CFB #1 off	92.5%	89.4%
2011/12 Winter	Asahi 12.5 kV	EKPC	Norwood Jct.-Shopville 69 kV Line (EKPC)	JK Smith CFB #1 off	92.5%	90.1%
2011/12 Winter	Hillsboro 25 kV	EKPC	Goddard-Hillsboro 69 kV Line (EKPC)	JK Smith CFB #1 off	92.5%	90.9%
2011/12 Winter	Hunt #1 25 kV	EKPC	Dale 138-69 kV Transformer (EKPC)	Brown #3 off	92.5%	91.6%
2011 Summer	Hunt #1 25 kV	EKPC	Dale 138-69 kV Transformer (EKPC)	Brown #3 off	92.5%	91.8%
2011 Summer	Perryville 12.5 kV	EKPC	None	Base	95.5%	95.1%

One voltage problem was identified without any contingencies. Additional low voltage problems for six different contingencies were identified for this scenario.

The transmission system expansion plan identified to mitigate the voltage problems identified in Table 2A is listed in Table 2B. This plan represents a reasonable and viable solution to the problems created by removal of all generation at Dale Station. A more detailed, thorough analysis should be performed if this generation scenario at Dale is pursued further to identify alternative plans and to confirm that this plan is the preferred alternative.

Prepared by:
EKPC Transmission Planning 11/5/2007

Table 2B Transmission Expansion Plan to Address System Problems for 0 MW Generation Output at Dale Station	
Project Description	**Estimated Cost in millions ($2007)**
Construct a 138/69 kV, 100 MVA Substation at Newby, including the facilities needed to connect the Newby Substation to E-ON's Brown Plant-Fawkes 138 kV line.	3.0
Install a 69 kV, 33.17 MVAR capacitor bank at the Dale Substation	0.5
Install a 69 kV, 16.84 MVAR capacitor bank at the Hope Substation	0.3
Install a 69 kV, 12.25 MVAR capacitor bank at the Stanton Substation	0.3
Total Cost	$4.1

Summary

The estimated costs of transmission expansion requirements range from $4.1M if all generating units at Dale Station are retired from service to $18.4M if the plant is re-powered to increase the net output to 650 MW. The analysis performed was a screening analysis to identify the expected problems and reasonable solutions. If changes to the generation levels at Dale are pursued further, the transmission analysis should be expanded to provide a more thorough evaluation of the issues and transmission alternatives.

Prepared by:
EKPC Transmission Planning 11/5/2007

APPENDIX B - Detailed Capital Cost Estimates

Case A - Cooper Unit 2 SDA / Financial Forecast Option

Case A - Cost Estimate Summary

	Case A - Capital Costs	
	Case A avg S	Case A max S
NOx emissions controls (SCR)	$59,455,761	$59,445,367
SO2 emission controls (SDA)	$167,506,185	$214,361,293
Stack breakout - included with SDA	$24,229,061	$24,487,337
Booster Fan breakout - incl. w/SDA	$5,144,891	$5,241,293
PM emission controls - Fabric Filter	$65,732,511	$70,128,495
Total Capital Requirement (TCR)	**$292,694,457**	**$343,935,155**

	Case A - O&M Costs	
	Case A avg S	Case A max S
NOx emissions controls (SCR)	$ 2,599,121	$ 2,598,755
SO2 emission controls (SDA)	$12,524,178	$23,372,773
Stack breakout - included with SDA	$166,142	$167,913
Booster Fan breakout - incl. w/SDA	$35,279	$35,940
PM emission controls - Fabric Filter	$1,302,836	$1,371,974
Total O&M Costs	**$ 16,426,135**	**$ 27,343,502**

Case B - Cooper 2 WFGD Option

Case B - Cost Estimate Summary

	Case B - Capital Costs	
	Case B avg S	Case B max S
NOx emissions controls (SCR)	$59,455,761	$59,445,266
SO2 emission controls (WFGD)	$247,704,308	$257,912,941
Stack breakout - included with SDA	$23,952,799	$24,067,434
Booster Fan breakout - incl. w/SDA	$6,921,548	$6,919,930
PM emission controls - ESP Upgrades	$689,370	$689,370
Total Capital Requirement (TCR)	**$307,849,439**	**$318,047,578**

	Case B - O&M Costs		
	Case B avg S	Case B max S	
NOx emissions controls (SCR)	$ 2,599,121	$ 2,598,749	$/year
SO2 emission controls (WFGD)	$9,895,843	$13,177,708	$/year
Stack breakout - included with SDA	$246,372	$247,551	$/year
Booster Fan breakout - incl. w/SDA	$71,193	$71,176	$/year
PM emission controls - ESP Upgrades	$689,370	$689,370	$/year
Total O&M Costs	**$ 13,184,334**	**$ 16,465,827**	$/year

Case A - Cooper Unit 2 SDA / Financial Forecast Option

NOx emissions controls (SCR)

	Case A		
	Case A avg S	Case A max S	
Total Capital Requirement (TCR)	**$59,455,761**	**$59,445,367**	Installed in 2012 Today's dollars
	$263	$263	$/kW
SCR O&M Costs			
Ammonia	$ 1,061,539	$ 1,061,543	$/year
Catalyst Replacement	$ 604,593	$ 604,392	$/year
Catalyst Disposal	$ 1,111	$ 1,110	$/year
Electricity	$ 147,679	$ 147,622	$/year
High-dust SCR Steam	$ 52,242	$ 52,242	$/year
Operating Labor	$ 76,591	$ 76,591	$/year
Maintenance	$ 655,367	$ 655,255	$/year
Total O&M Costs	**$ 2,599,121**	**$ 2,598,755**	$/year

SO2 emission controls (SDA - semi-dry scrubber)

	Case A		
	Case A avg S	Case A max S	
Total Capital Requirement (TCR)	**$167,506,185**	**$214,361,293**	Installed in 2012 Today's dollars
	$741	$949	$/kW
Maintenance Costs	$872,870	$1,109,216	$/year
Fixed O&M Costs	$2,059,639	$2,324,347	$/year
Variable Operating Costs	$9,591,669	$19,939,211	$/year
Total O&M Costs	**$12,524,178**	**$23,372,773**	$/year

Stack breakout - included with SDA costs above

	Case A		
	Case A avg S	Case A max S	
Total Capital Requirement (TCR)	**$24,229,061**	**$24,487,337**	Today's dollars
Maintenance Costs	$166,142	$167,913	$/year

Booster Fan breakout - included with SDA costs above

	Case A		
	Case A avg S	Case A max S	
Total Capital Requirement (TCR)	**$5,144,891**	**$5,241,293**	Today's dollars
Maintenance Costs	$35,279	$35,940	$/year

Particulate Matter (PM) emission controls (Fabric Filter)

	Case A		
	Case A avg S	Case A max S	
Total Capital Requirement (TCR)	**$65,732,511**	**$70,128,495**	Installed in 2012 Today's dollars
	$291	$310	$/kW
Power Cost	$266,296	$273,694	$/year
Maintenance Costs	$841,449	$897,722	$/year
Periodic Replacement Items	$195,091	$200,557	$/year
Total O&M Costs	**$1,302,836**	**$1,371,974**	$/year

Case B - Cooper 2 WFGD Option

NOx emissions controls (SCR)

	Case B		
	Case B avg S	Case B max S	Installed in 2012
Total Capital Requirement (TCR)	**$59,455,761**	**$59,445,266**	Today's dollars
	$263	$263	$/kW
SCR O&M Costs			
Ammonia	$ 1,061,539	$ 1,061,543	$/year
Catalyst Replacement	$ 604,593	$ 604,387	$/year
Catalyst Disposal	$ 1,111	$ 1,110	$/year
Electricity	$ 147,679	$ 147,622	$/year
High-dust SCR Steam	$ 52,242	$ 52,242	$/year
Operating Labor	$ 76,591	$ 76,591	$/year
Maintenance	$ 655,367	$ 655,254	$/year
Total O&M Costs	**$ 2,599,121**	**$ 2,598,749**	$/year

SO2 emission controls (WFGD - wet scrubber)

	Case B		
	Case B avg S	Case B max S	
Total Capital Requirement (TCR)	**$247,704,308**	**$257,912,941**	Today's dollars
	$1,096	$1,141	$/kW
Maintenance Costs	$1,949,386	$2,026,522	$/year
Fixed O&M Costs	$3,515,381	$3,601,775	$/year
Variable Operating Costs	$4,431,076	$7,549,411	$/year
Total O&M Costs	**$9,895,843**	**$13,177,708**	$/year

Stack breakout - included with WFGD costs above

	Case B		
	Case B avg S	Case B max S	
Total Capital Requirement (TCR)	**$23,952,799**	**$24,067,434**	Today's dollars
Maintenance Costs	$246,372	$247,551	$/year

Booster Fan breakout - included with WFGD costs above

	Case B		
	Case B avg S	Case B max S	
Total Capital Requirement (TCR)	**$6,921,548**	**$6,919,930**	Today's dollars
Maintenance Costs	$71,193	$71,176	$/year

Particulate Matter (PM) emission controls (ESP upgrades)

	Case B
Cost Estimate per JBM Incorporated proposal	
Total Material Price	$265,035
Total Install Price	$424,335
Total	**$689,370**

Alternate - Particulate Matter (PM) emission controls (New ESP Unit)

	Case B		
	Case B avg S	Case B max S	
Total Capital Requirement (TCR)	**$67,738,511**	**$67,656,545**	Today's dollars
	$300	$299	$/kW
Power Cost	$88,706	$81,291	$/year
Maintenance Costs	$867,128	$866,079	$/year
Total O&M Costs	**$955,834**	**$947,369**	$/year

Summary of Inputs Used

COAL ULTIMATE ANALYSIS (ASTM, as rec'd)		Cooper 2 Average Sulfur Content	Cooper 2 Maximum Sulfur Content
Moisture	wt%	6 68	6 68
Carbon	wt%	64 18	64 18
Hydrogen	wt%	4 20	4 20
Nitrogen	wt%	1 42	1 42
Chlorine	wt%	0 10	0 10
Sulfur	wt%	2 23	4 20
Ash	wt%	13 67	13 67
Oxygen	wt%	7 52	5 55
TOTAL	wt%	100 00	100 00
Modified Mott Spooner HHV (Btu/lb) - *calc*	Btu/lb	11,419 00	11,621 00
COAL ASH ANALYSIS (ASTM, as rec'd)			
SiO2	wt%	53 40	53 40
Al2O3	wt%	23 40	23 40
TiO2	wt%	1 34	1 34
Fe2O3	wt%	15 30	15 30
CaO	wt%	1 71	1 71
MgO	wt%	1 02	1 02
Na2O	wt%	0 25	0 25
K2O	wt%	2 28	2 28
P2O5	wt%	0 47	0 47
SO3	wt%	0 28	0 28
Other Unaccounted for	wt%	0 55	0 55
TOTAL	wt%	100 00	100 00

		Case A avg S	Case A max S	Case B avg S	Case B max S
Location - State	Abbrev	KY	KY	KY	KY
MW Equivalent of Flue Gas to Control System	MW	226	226	226	226
Net Plant Heat Rate (w/o APC)	Btu/kWhr	10240	10240	10240	10240
Plant Capacity Factor	%	0 85	0 85	0 85	0 85
Percent Excess Air in Boiler	%	1 2	1 2	1 2	1 2
Air Heater Inleakage	%	0 13	0 13	0 13	0 13
Air Heater Outlet Gas Temperature	°F	290	290	290	290
Inlet Air Temperature	°F	79	79	79	79
Ambient Absolute Pressure	In of Hg	29 08	29 08	29 08	29 08
Pressure After Air Heater	In of H2O	-14 5	-14 5	-14 5	-14 5
Moisture in Air	lb/lb dry air	0 013	0 013	0 013	0 013
Ash Split:					
Fly Ash	%	80%	80%	80%	80%
Bottom Ash	%	20%	20%	20%	20%

Economic Inputs		Case A avg S	Case A max S	Case B avg S	Case B max S
Cost Basis -Year Dollars	Year	2012	2012	2012	2012
Sevice Life (levelization period)	Years	20	20	20	20
Inflation Rate	%	3 00%	3 00%	3 00%	3 00%
After Tax Discount Rate (current $'s)	%	7 00%	7 00%	7 00%	7 00%
AFDC Rate (current $'s)	%	10 80%	10 80%	10 80%	10 80%
First-year Carrying Charge (current $'s)	%	9 44%	9 44%	9 44%	9 44%
Levelized Carrying Charge (current $'s)	%	9 44%	9 44%	9 44%	9 44%
First-year Carrying Charge (*constant* $'s)	%	9 44%	9 44%	9 44%	9 44%
Levelized Carrying Charge (constant $'s)	%	9 44%	9 44%	9 44%	9 44%
Sales Tax **(SCR, ESP - Yes. LSFO, FF-?)**	%	0%	0%	0%	0%
Escalation Rates:					
Consumables (O&M)	%	3%	3%	3%	3%
Capital Costs:					
Is Chem Eng Cost Index available?	Yes / No	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index	Integer	499 6	499 6	499 6	499 6
If "No" input escalation rate	%	3%	3%	3%	3%
Construction Labor Rate (Not Used N Calc)	$/hr	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%
Operating Labor Rate	$/hr	$30	$30	$30	$30
Power Cost	Mills/kWh	25	25	25	25
Steam Cost	$/1000 lbs	3 5	3 5	3 5	3 5

Lime Spray Dryer (LSD) Inputs		Case A avg S	Case A max S	Case B avg S	Case B max S
SO2 Removal Required	%	95%	95%	95%	95%
Adiabatic Saturation Temperature	°F	125 5	125 5	125 5	125 5
Flue Gas Approach to Saturation	°F	25	25	25	25
Spray Dryer Outlet Temperature	°F	150 5	150 5	150 5	150 5
Reagent Feed Ratio (Mole CaO / Mole Inlet SO2)	Factor	1 47	2 11	1 47	2 11
Recycle Rate (lb recycle / lb lime feed)	Factor	1 6	0 34	1 6	0 34
Recycle Slurry Solids Concentration	Wt %	35%	35%	35%	35%
Number of Absorbers (Max Capacity = 300 MW per spray dryer)	Integer	1	1	1	1
Absorber Material (1 = alloy, 2 = RLCS, 3=CS**)	Integer	3	3	3	3
Spray Dryer Pressure Drop	in H2O	5	5	5	5
Reagent Bulk Storage	Days	30	30	30	30
Reagent Cost (delivered)	$/ton	$81	$81	$81	$81
Dry Waste Disposal Cost	$/ton, dry	$30	$30	$30	$30
Maintenance Factors by Area (% of Installed Cost)					
Reagent Feed	%	2%	2%	2%	2%
SO2 Removal	%	2%	2%	2%	2%
Flue Gas Handling	%	2%	2%	2%	2%
Waste / Byproduct	%	2%	2%	2%	2%
Support Equipment	%	2%	2%	2%	2%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%

Particulate Control Inputs		Case A avg S	Case A max S	Case B avg S	Case B max S
Outlet Particulate Emission Limit	lbs/MMBtu	0 03	0 03	0 03	0 03
Fabric Filter:					
Pressure Drop	in H2O	9	9	9	9
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	2	2
Gas-to-Cloth Ratio	$ACFM/ft^2$	3 5	3 5	3 5	3 5
Bag Material (RGFF fiberglass only) (1 = Fiberglass, 2 = Nomex, 3 = Ryton)	Integer	3	3	3	3
Bag Diameter	inches	6	6	6	6
Bag Length	feet	26	26	26	26
Bag Reach		3	3	3	3
Compartments out of Service	%	10%	10%	10%	10%
Bag Life	Years	3	3	3	3
Maintenance (% of installed cost)	%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%

Selective Catalytic Reduction (SCR) Inputs		Case A avg S	Case A max S	Case B avg S	Case B max S
NH3/NOX Stoichiometric Ratio	NH3/NOX	0 941	0 941	0 941	0 941
NOX Reduction Efficiency	Fraction	0 9	0 9	0 9	0 9
Inlet NOx	lbs/MMBtu	0 45	0 45	0 45	0 45
Space Velocity (Calculated if zero)	1/hr	D	D	D	D
Overall Catalyst Life	years	D	D	D	D
Ammonia Cost	$/ton	540	540	540	540
Catalyst Cost	$/ft3	150	150	150	150
Solid Waste Disposal Cost	$/ton	D	D	D	D
Maintenance (% of installed cost)	%	D	D	D	D
Contingency (% of installed cost)	%	D	D	D	D
General Facilities (% of installed cost)	%	D	D	D	D
Engineering Fees (% of installed cost)	%	D	D	D	D
Number of Reactors	integer	D	D	D	D
Number of Air Preheaters	integer	2	2	2	2

Case C - Cooper Unit 1&2 WFGD Option

Case C - Cooper Unit 1&2 WFGD Option

NOx emissions controls (SCR)

	Case C		Case C		
	Unit 1	Unit 1	Unit 2	Unit 2	
	Case C avg S	Case C avg S	Case C avg S	Case C max S	Installed in 2012
Total Capital Requirement (TCR)	**$38,094,856**	**$38,088,466**	**$59,455,761**	**$59,445,266**	Today's dollars
	$331	$331	$263	$263	$/kW
SCR O&M Costs					
Ammonia	$ 533,834	$ 533,836	$ 1,061,539	$ 1,061,543	$/year
Catalyst Replacement	$ 304,042	$ 303,940	$ 604,593	$ 604,387	$/year
Catalyst Disposal	$ 558	$ 558	$ 1,111	$ 1,110	$/year
Electricity	$ 65,096	$ 65,067	$ 147,679	$ 147,622	$/year
High-dust SCR Steam	$ 26,246	$ 26,246	$ 52,242	$ 52,242	$/year
Operating Labor	$ 58,732	$ 58,732	$ 76,591	$ 76,591	$/year
Maintenance	$ 439,893	$ 439,821	$ 655,367	$ 655,254	$/year
Total O&M Costs	**$ 1,428,400**	**$ 1,428,200**	**$ 2,599,121**	**$ 2,598,749**	$/year

SO2 emission controls (Combined U1/2 WFGD - wet scrubber)

	Case C		
	Case C avg S	Case C avg S	
Total Capital Requirement (TCR)	**$291,027,851**	**$304,943,632**	Installed in 2012 Today's dollars
	$853	$894	$/kW
Maintenance Costs	$2,288,621	$2,393,289	$/year
Fixed O&M Costs	$4,323,586	$4,440,813	$/year
Variable Operating Costs	$6,664,422	$11,350,925	$/year
Total O&M Costs	**$13,276,629**	**$18,185,027**	$/year

Stack breakout - included with WFGD costs above

	Case C		
	Case C avg S	Case C avg S	
Total Capital Requirement (TCR)	**$26,080,406**	**$26,205,223**	Today's dollars
Maintenance Costs	$288,891	$290,273	$/year

Booster Fan breakout - included with WFGD costs above

	Case C		
	Case C avg S	Case C avg S	
Total Capital Requirement (TCR)	**$9,146,525**	**$9,144,387**	Today's dollars
Maintenance Costs	$94,079	$94,057	$/year

Particulate Matter (PM) emission controls (Combined U1/2 Fabric Filter)

	Case C		
	Case C avg S	Case C avg S	
Total Capital Requirement (TCR)	**$95,507,151**	**$95,385,300**	Installed in 2012 Today's dollars
	$280	$280	$/kW
Power Cost	$133,315	$122,171	$/year
Maintenance Costs	$1,222,597	$1,221,037	$/year
			$/year
Total O&M Costs	**$1,355,912**	**$1,343,208**	$/year

Case C - Cooper 1&2 WFGD Option

Case C - Cost Estimate Summary

	Case C - Capital Costs	
	Case C avg S	Case C avg S
NOx emissions controls (Separate SCRs)	$97,550,617	$97,533,732
SO2 emission controls (WFGD)	$291,027,851	$304,943,632
Stack breakout - included with WFGD	$26,080,406	$26,205,223
Booster Fan breakout - incl. w/WFGD	$9,146,525	$9,144,387
PM emission controls - Fabric Filter	$95,507,151	$95,385,300
Total Capital Requirement (TCR)	**$484,085,619**	**$497,862,664**

	Case C - O&M Costs	
	Case C avg S	Case C avg S
NOx emissions controls (Separate SCRs)	$ 4,027,521	$ 4,026,949
SO2 emission controls (WFGD)	$13,276,629	$18,185,027
Stack breakout - included with WFGD	$288,891	$290,273
Booster Fan breakout - incl. w/WFGD	$94,079	$94,057
PM emission controls - Fabric Filter	$1,355,912	$1,343,208
Total O&M Costs	**$ 18,660,062**	**$ 23,555,184**

East Kentucky Power Cooperative Cooper Repower Repower Cooper 2 with CFB (Case D) Preliminary Cost Estimates B&McD Project No.: 46644		13-Dec-07 250 MW
No.	**Item**	
1	PROCUREMENT	
2	Equipment Cost	$ 200,000,000
3	SCNR / Baghouse (1	$ -
4	Civil / Electrical / Other BOP	$ 24,000,000
5	Coal / Limestone Handling / Storage	$ 17,000,000
6	PROCUREMENT SUBTOTAL	$ 241,000,000
7	CONSTRUCTION	$ 50,000,000
8	PROJECT & OWNER INDIRECTS	$ 55,000,000
10	ENGINEERING / PROJECT MANAGEMENT	$ 45,000,000
11	INTEREST DURING CONSTRUCTION	$ 27,370,000
12	CONTINGENCY	$ 62,755,500
13	TOTAL PROJECT COST W/ CONTINGENCY	$ 481,125,500

(1) Included in Equipment Cost

CASE F: Dale Units 3 & 4 Repower: 2 - 1x1 CCGT 7FA

General Inflation	(%)	2.5%
Heat Rate - Full Load with Duct Firing [1]	(Btu/kWh)	N/A
Heat Rate - Full Load without Duct Firing (240 MW)	(Btu/kWh)	8,200
Heat Rate - 75% Load (180 MW)	(Btu/kWh)	8,610
Heat Rate - 50% Load (120 MW)	(Btu/kWh)	9,350
Total Project Capacity	(MW)	480
New Project Capacity	(MW)	330
COD [2]	(Year)	2012
Construction Period	(Years)	2
Capital Cost [3]	(2007$)	$245,600,000
Project Indirects & Owner's Cost	(2007$)	$80,900,000
Site Retirement Costs	(2007$)	$2,700,000
Total Cost w/out Escalation	(2007$)	$329,200,000
Escalation	($)	$25,300,000
Interest During Construction [4]	($)	$23,800,000
Total Project Cost	**(2012$)**	**$378,300,000**
Total Project Cost (per Total Capacity)	**(2012$/kW)**	**$788**
Fixed O&M (excl. property tax/insurance)	**(2007$/kW-yr)**	**$7.29**
Variable O&M (Excl. Major Maintenance)	**(2007$/MWh)**	**$1.58**
GT Major Maintenance [5], Cost per Hour	**(2007$/hour)**	**$500**
GT Major Maintenance [5], Cost per Start	**(2007$/start)**	**$15,000**
Emissions Estimates (lbs/MMBtu)		
NO_x	0.007	
SO_2	< 0.0051	
CO	0.013	
CO_2	118	
Hg (lbs/Tbtu)	N/A	

Notes:

1. Heat Rate based on HHV, based on per unit basis not plant basis
2. COD reflects earliest start date (with allowance for development, permitting, and construction
3. Capital costs do not include escalation
4. IDC reflects 6% interest rate
5. Major Maintenance based on hours or starts. If hours per start is greater than 30 hours, then hours based maintenance is triggered. If hours per start is less than 30 hours, then starts based maintenance is triggered.

CASE G: Dale Units 3 & 4 Repower: 2 - 1x1 CCGT 7EA

General Inflation	(%)	2.5%
Heat Rate - Full Load with Duct Firing (160 MW) [1]	(Btu/kWh)	8,620
Heat Rate - Full Load without Duct Firing (128 MW)	(Btu/kWh)	8,400
Heat Rate - 75% Load (96 MW)	(Btu/kWh)	8,820
Heat Rate - 50% Load (64 MW)	(Btu/kWh)	9,575
Total Project Capacity	(MW)	320
New Project Capacity	(MW)	170
COD [2]	(Year)	2012
Construction Period	(Years)	2
Capital Cost [3]	(2007$)	$202,400,000
Project Indirects & Owner's Cost	(2007$)	$76,500,000
Site Retirement Costs	(2007$)	$2,700,000
Total Cost w/out Escalation	(2007$)	$281,600,000
Escalation	($)	$21,700,000
Interest During Construction [4]	($)	$20,300,000
Total Project Cost	**(2012$)**	**$323,600,000**
Total Project Cost (per Total Capacity)	**(2012$/kW)**	**$1,011**
Fixed O&M (excl. property tax/insurance)	**(2007$/kW-yr)**	**$10.94**
Variable O&M (Excl. Major Maintenance)	**(2007$/MWh)**	**$2.35**
GT Major Maintenance [5], Cost per Hour	**(2007$/hour)**	**$200**
GT Major Maintenance [5], Cost per Start	**(2007$/start)**	**$6,000**
Emissions Estimates (lbs/MMBtu)		
NO_x	0.007	
SO_2	< 0.0051	
CO	0.013	
CO_2	118	
Hg (lbs/Tbtu)	N/A	

Notes:
1. Heat Rate based on HHV, based on per unit basis not plant basis
2. COD reflects earliest start date (with allowance for development, permitting, and construction
3. Capital costs do not include escalation
4. IDC reflects 6% interest rate
5. Major Maintenance based on hours or starts. If hours per start is greater than 30 hours, then hours based maintenance is triggered. If hours per start is less than 30 hours, then starts based maintenance is triggered.

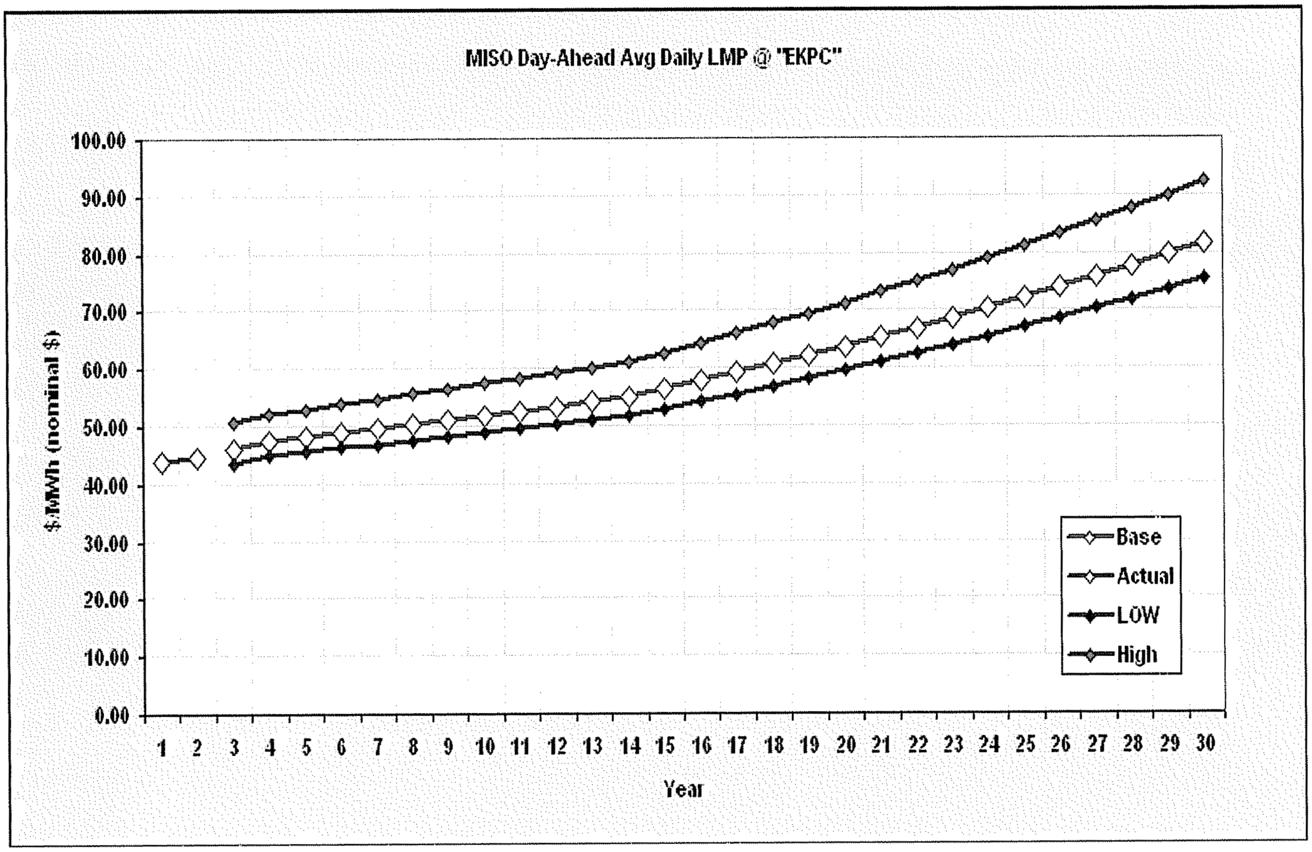
East Kentucky Power Cooperative		13-Dec-07
Dale Repower		
Repower Dale 3-4 with CFB (CaseH)		150 MW
Preliminary Cost Estimates		
B&McD Project No.: 46644		
No.	Item	
1	PROCUREMENT	
2	Equipment Cost	$ 85,000,000
3	SCNR / Baghouse	$ 25,000,000
4	Civil / Electrical / Other BOP (1)	$ -
5	Coal / Limestone Handling / Storage	$ 25,000,000
6	PROCUREMENT SUBTOTAL	$ 135,000,000
7	CONSTRUCTION	$ 42,500,000
8	PROJECT & OWNER INDIRECTS	$ 34,000,000
10	ENGINEERING / PROJECT MANAGEMENT	$ 35,000,000
11	INTEREST DURING CONSTRUCTION	$ 17,680,796
12	CONTINGENCY	$ 40,539,539
13	Site Remuneration	$ 6,082,800
14	TOTAL PROJECT COST W/ CONTINGENCY	$ 310,803,135
(1) Included construction cost		

APPENDIX C - LMP Forecast

East Kentucky Power Cooperative
Power Plant Assessment Study
Forecast of MISO Day-Ahead LMP @ "EKPC" (Nominal $)

	MISO Average Day Ahead LMP		
Year	Low Avg Daily LMP for Year	Base Avg Daily LMP for Year	High Avg Daily LMP for Year
	Nominal $ $/MWh	Nominal $ $/MWh	Nominal $ $/MWh
2006	$43.86	$43.86	$43.86
2007	$44.74	$44.74	$44.74
2008	$43.69	$45.99	$50.59
2010	$45.58	$48.08	$52.99
2012	$46.87	$49.54	$54.71
2014	$48.20	$51.04	$56.48
2016	$49.56	$52.59	$58.31
2018	$50.96	$54.18	$60.20
2020	$52.92	$56.38	$62.76
2022	$55.50	$59.24	$66.09
2024	$58.20	$62.25	$69.58
2026	$61.04	$65.42	$73.27
2028	$64.01	$68.74	$77.15
2030	$67.13	$72.24	$81.23
2032	$70.40	$75.91	$85.53
2034	$73.84	$79.77	$90.06

East Kentucky Power Cooperative
Power Plant Assessment Study
Forecast of MISO Day-Ahead LMP @ "EKPC" (Nominal $)



APPENDIX D - Fuel Forecast

PLANT	COMPANY	MINE	LOCATION	RR	LOADOUTS	FRGHT DIST	NOTES
COOPER	GATLIFF COAL CO.	GATLIFF	BELL COUNTY, KY	CSXT	ADA	JELLICO-MIDDLESBORO	TRUCK
	NATIONAL COAL CORP.	PINE MTN.	BELL COUNTY, KY	CSXT	VIALL	JELLICO-MIDDLESBORO	TRUCK
	NATIONAL COAL CORP.	STRAIGHT CREEK	BELL COUNTY, KY	CSXT	VIALL	JELLICO-MIDDLESBORO	TRUCK
	NATIONAL COAL CORP.	TURLEY TIPPLE	CAMPBELL, TN	CSXT	TURLEY	JELLICO-MIDDLESBORO	TRUCK
	ICG	ICG TYPO	PERRY, KY	CSXT	TYPO	HAZARD	TRUCK
	TRINITY COAL MARKETING	LITTLE ELK MINING	PERRY, KY	CSXT	SIGMON	HAZARD	TRUCK
DALE	GATLIFF COAL	GATLIFF	BELL COUNTY, KY	CSXT	ADA	JELLICO-MIDDLESBORO	TRUCK
	TRINITY COAL MARKETING	LITTLE ELK MINING	PERRY, KY	CSXT	PERRY	HAZARD	TRUCK
	B&W RESOURCES INC.			CSXT	RESOURCE	JELLICO-MIDDLESBORO	TRUCK
	ARGUS ENERGY,LLC.			NS			TRUCK
	IKERD TERMINAL COMPANY	FERGUSON	SOMERSET, KY	NS	FERGUSON	SOMERSET DISTRICT	TRUCK

HILL & ASSOCIATES, A WOOD MACKENZIE COMPANY 7-Nov-07

BURNS & MCDONNELL / EAST KENTUCKY POWER COOPERATIVE
DELIVERED COAL ANALYSIS: COOPER & DALE PLANTS
COAL ORIGIN: EASTERN KENTUCKY, TENNESSEE
ORIGINATING RAILROAD:COOPER=NORFOLK SOUTHERN (NS), DALE=CSXT DRAFT
DELIVERING RAILROAD: COOPER=NS, DALE=CSXT
CURRENT DELIVERIES: COOPER/DALE=TRUCK
COAL TYPE: EKY MID BTU, COMPLIANCE, EKY MID BTU, LOW SULFUR (<1%), EKY, MID BTU, MID SULFUR, TN, NEAR COMPLIANCE

2007 OUTLOOK PRICE FORECAST (2007 CONSTANT $)

EKPC REGIONAL COAL TRANSPORTATION ESTIMATES													RAIL TRANSPORTATION								TRUCK TRANSPORTATION						TOTAL TRANSPORTATION COST			
SITE	SITE CODE	BASIN NAME	BASIN ID	REGION	FLAVOR	CODER	CODEF	BTU	%SULF	HGI	LBSO2/MM	LBHG/TBTU	ORIGIN	R-1 RAIL CARRIER	R-1 MILES	R-1 RATE	R-1 RAIL COST	R-1 DEST.	R-1 TO R-2 HTCHG CHARGE	R-1 + R-2 TOTAL COST	T-1 ORIG.	T-1 TRUCK CARRIER	T-1 BASE	T-1 MILES	T-1 RATE	T-1 COST	R-1 & R-2 RAIL	T-1 TRUCK	B-1 BARGE	TOTAL TRANS. COST
RAIL DELIVERY																														
DALE	CAPP	CENTRAL APP., KY		E. KY-MID BTU-CSX	COMPLIANCE, HIGH FUSION	YMC	CPH	12500	0.63	45	1.1	5.18	ADA	CSXT	55.0	0.17960	$9.88	FORD, KY	$0.00	$9.88							$ 9.88	$ -	$ -	$ 9.88
DALE	CAPP	CENTRAL APP., KY		E. KY-MID BTU-CSX	NEAR-COMPLIANCE, HIGH FUSION	YMC	NCH	12500	1.12	44	1.79	7.44	VALL	CSXT	69.9	0.15930	$11.14	FORD, KY	$0.00	$11.14							$ 11.14	$	$ -	$ 11.14
DALE	CAPP	CENTRAL APP., KY		E. KY-MID BTU-CSX	MID-SULFUR	YMC	MSZ	12300	1.75	47	2.85	10.38	TYPO	CSXT	129.1	0.12150	$15.69	FORD, KY	$0.00	$15.69							$ 15.69	$	$ -	$ 15.69
TRUCK DELIVERY																														
DALE	CAPP	CENTRAL APP., KY		E. KY-MID BTU-CSX	COMPLIANCE, HIGH FUSION	YMC	CPH	12500	0.63	45	1.1	5.18							$0.00	$0.00	ADA		$1.50	95.0	$0.10	$11.00	$ -	$11.00	$ -	$ 11.00
DALE	CAPP	CENTRAL APP., KY		E. KY-MID BTU-CSX	NEAR-COMPLIANCE, HIGH FUSION	YMC	NCH	12500	1.12	44	1.79	7.44							$0.00	$0.00	VALL		$1.50	110.0	$0.10	$12.50	$	$12.50	$ -	$ 12.50
DALE	CAPP	CENTRAL APP., KY		E. KY-MID BTU-CSX	MID-SULFUR	YMC	MSZ	12300	1.75	47	2.85	10.38							$0.00	$0.00	TYPO		$1.50	117.0	$0.10	$13.20	$	$13.20	$ -	$ 13.20
RAIL DELIVERY																														
COOPER	CAPP	CENTRAL APP., KY		E. KY-MID BTU-NS	COMPLIANCE, HIGH FUSION	YMN	CPH	12700	0.67	45	1.06	5.18	PIONEER	NS	224.2	0.0723	$16.21	SOMERSET, KY	$0.00	$16.21							$ 16.21	$	$ -	$ 16.21
COOPER	CAPP	CENTRAL APP., KY		E. KY-MID BTU-NS	MID-SULFUR	YMN	MSZ	12100	1.74	45	2.88	10.38	STEARNS	NS	31.3	0.207	$6.48	SOMERSET, KY	$0.00	$6.48							$ 6.48	$ -	$ -	$ 6.48
COOPER	CAPP	CENTRAL APP., KY		E. KY-MID BTU-NS	NEAR-COMPLIANCE, HIGH FUSION	YMN	NCH	12500	1.00	45	1.63	7.44	PIONEER	NS	224.2	0.0723	$16.21	SOMERSET, KY	$0.00	$16.21							$ 16.21	$ -	$ -	$ 16.21
COOPER	CAPP	CENTRAL APP., TN		TENNESSEE	NEAR-COMPLIANCE, HIGH FUSION	TEN	NCH	12900	1.23	60	1.99	7.77	TURLEY	NS	150	0.075	$11.25	SOMERSET, KY	$0.00	$11.25							$ 11.25	$ -	$	$ 11.25
TRUCK DELIVERY																														
COOPER	CAPP	CENTRAL APP., KY		E. KY-MID BTU-NS	COMPLIANCE, HIGH FUSION	YMN	CPH	12700	0.67	45	1.06	5.18							$0.00	$0.00	ADA		$1.50	73.0	$0.10	$8.80	$ -	$8.80	$ -	$ 8.80
COOPER	CAPP	CENTRAL APP., KY		E. KY-MID BTU-NS	MID-SULFUR	YMN	MSZ	12100	1.74	45	2.88	10.38							$0.00	$0.00	VALL		$1.50	83.0	$0.10	$9.80	$ -	$9.80	$	$ 9.80
COOPER	CAPP	CENTRAL APP., KY		E. KY-MID BTU-NS	NEAR-COMPLIANCE, HIGH FUSION	YMN	NCH	12500	1.00	45	1.63	7.44							$0.00	$0.00	TYPO		$1.50	106.0	$0.10	$12.10	$ -	$12.10	$ -	$ 12.10
COOPER	CAPP	CENTRAL APP., TN		TENNESSEE	NEAR-COMPLIANCE, HIGH FUSION	TEN	NCH	12900	1.23	60	1.99	7.77							$0.00	$0.00	TURLEY		$1.50	59	$0.10	$7.40	$	$7.40	$ -	$ 7.40

COOPER = NS
DALE=CSXT

Dale	Ada	95
Cooper	Ada	73
Dale	Vall	110
Cooper	Vall	83
Dale	Typo	117
Cooper	Typo	106
Cooper	Turley	59

HILL & ASSOCIATES, A WOOD MACKENZIE COMPANY

7-Nov-07

BURNS & MCDONNELL / EAST KENTUCKY POWER COOPERATIVE

DELIVERED COAL ANALYSIS: COOPER & DALE PLANTS

COAL ORIGIN: EASTERN KENTUCKY, TENNESSEE

ORIGINATING RAILROAD:COOPER=NORFOLK SOUTHERN (NS), DALE=CSXT

DRAFT

DELIVERING RAILROAD: COOPER=NS, DALE=CSXT

CURRENT DELIVERIES: COOPER/DALE=TRUCK

COAL TYPE: EKY MID BTU, COMPLIANCE, EKY MID BTU, LOW SULFUR (<1%), EKY, MID BTU, MID SULFUR, TN, NEAR COMPLIANCE

2007 OUTLOOK PRICE FORECAST (2007 CONSTANT $)

FOB MINE PRICE FORECAST, $/TON

Plant Name	BASIN_ID	BASIN_NAME	MINE_STATE	REGION	FLAVOR	CODER	CODEF	BTU	PCT_SULF	GRIND	LBSO2MM	LBHGTBTU	FOB $/TON	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	COMPLIANCE, HIGH FUSION	YMC	CPH	12500	0.69	45	1.10	5.18	2007 FORECAST	$ 48.73	$ 46.20	$ 45.14	$ 43.95	$ 43.51	$ 42.58	$ 42.58	$ 44.83	$ 44.81	$ 45.79	$ 47.02	$ 48.47
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	NEAR-COMPLIANCE, HIGH FUSION	YMC	NCH	12600	1.12	44	1.78	7.44	2007 FORECAST	$ 44.89	$ 44.89	$ 44.97	$ 43.75	$ 43.22	$ 42.51	$ 42.18	$ 43.68	$ 43.02	$ 43.72	$ 44.21	$ 44.93
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	MID-SULFUR	YMC	MSZ	12300	1.75	47	2.85	10.38	2007 FORECAST	$ 42.66	$ 43.02	$ 43.64	$ 42.01	$ 41.47	$ 40.79	$ 40.43	$ 41.89	$ 41.23	$ 41.88	$ 42.22	$ 42.88
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	COMPLIANCE, HIGH FUSION	YMN	CPH	12700	0.67	45	1.06	5.18	2007 FORECAST	$ 50.01	$ 47.56	$ 47.21	$ 45.59	$ 44.98	$ 44.62	$ 44.65	$ 46.87	$ 46.61	$ 47.39	$ 48.46	$ 49.99
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	MID-SULFUR	YMN	MSZ	12100	1.74	45	2.88	10.38	2007 FORECAST	$ 45.64	$ 45.76	$ 45.80	$ 44.50	$ 43.95	$ 43.60	$ 43.50	$ 44.96	$ 44.12	$ 44.38	$ 44.79	$ 45.40
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	NEAR-COMPLIANCE, HIGH FUSION	YMN	NCH	12300	1.00	45	1.63	7.44	2007 FORECAST	$ 44.24	$ 44.01	$ 44.86	$ 43.29	$ 42.83	$ 42.52	$ 42.47	$ 44.12	$ 43.59	$ 44.19	$ 44.46	$ 44.92
COOPER	CAPP	CENTRAL APP.	TN	TENNESSEE	NEAR-COMPLIANCE, HIGH FUSION	TEN	NCH	12900	1.23	60	1.90	7.77	2007 FORECAST	$ 49.51	$ 50.24	$ 50.33	$ 49.47	$ 49.66	$ 49.47	$ 49.28	$ 49.27	$ 48.96	$ 48.76	$ 48.80	$ 49.51

RAIL DELIVERED PRICE FORECAST, $/TON

Plant Name	BASIN_ID	BASIN_NAME	MINE_STATE	REGION	FLAVOR	CODER	CODEF	BTU	PCT_SULF	GRIND	LBSO2MM	LBHGTBTU	DELVD $/TON	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	COMPLIANCE, HIGH FUSION	YMC	CPH	12500	0.69	45	1.10	5.18	2007 FORECAST	$ 58.61	$ 56.08	$ 55.02	$ 53.83	$ 53.39	$ 52.46	$ 52.46	$ 54.71	$ 54.69	$ 55.67	$ 56.90	$ 58.35
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	NEAR-COMPLIANCE, HIGH FUSION	YMC	NCH	12600	1.12	44	1.78	7.44	2007 FORECAST	$ 56.03	$ 56.03	$ 56.11	$ 54.89	$ 54.36	$ 53.65	$ 53.32	$ 54.82	$ 54.16	$ 54.86	$ 55.35	$ 56.07
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	MID-SULFUR	YMC	MSZ	12300	1.75	47	2.85	10.38	2007 FORECAST	$ 58.35	$ 58.71	$ 59.33	$ 57.70	$ 57.16	$ 56.48	$ 56.12	$ 57.58	$ 56.92	$ 57.57	$ 57.91	$ 58.57
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	COMPLIANCE, HIGH FUSION	YMN	CPH	12700	0.67	45	1.06	5.18	2007 FORECAST	$ 66.22	$ 63.77	$ 63.42	$ 61.80	$ 61.19	$ 60.83	$ 60.86	$ 63.08	$ 62.82	$ 63.60	$ 64.67	$ 66.20
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	MID-SULFUR	YMN	MSZ	12100	1.74	45	2.88	10.38	2007 FORECAST	$ 52.12	$ 52.24	$ 52.28	$ 50.98	$ 50.43	$ 50.08	$ 49.98	$ 51.44	$ 50.60	$ 50.86	$ 51.27	$ 51.88
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	NEAR-COMPLIANCE, HIGH FUSION	YMN	NCH	12300	1.00	45	1.63	7.44	2007 FORECAST	$ 60.45	$ 60.22	$ 61.07	$ 59.50	$ 59.04	$ 58.73	$ 58.68	$ 60.33	$ 59.80	$ 60.40	$ 60.67	$ 61.13
COOPER	CAPP	CENTRAL APP.	TN	TENNESSEE	NEAR-COMPLIANCE, HIGH FUSION	TEN	NCH	12900	1.23	60	1.90	7.77	2007 FORECAST	$ 60.76	$ 61.49	$ 61.58	$ 60.72	$ 60.91	$ 60.72	$ 60.53	$ 60.52	$ 60.21	$ 60.01	$ 60.05	$ 60.76

HILL & ASSOCIATES, A WOOD MACKENZIE COMPANY 7-Nov-07

BURNS & MCDONNELL / EAST KENTUCKY POWER COOPERATIVE

DELIVERED COAL ANALYSIS: COOPER & DALE PLANTS

COAL ORIGIN: EASTERN KENTUCKY, TENNESSEE

ORIGINATING RAILROAD:COOPER=NORFOLK SOUTHERN (NS), DALE=CSXT DRAFT

DELIVERING RAILROAD: COOPER=NS, DALE=CSXT

CURRENT DELIVERIES: COOPER/DALE=TRUCK

COAL TYPE: EKY MID BTU, COMPLIANCE, EKY MID BTU, LOW SULFUR (<1%), EKY, MID BTU, MID SULFUR, TN, NEAR COMPLIANCE

2007 OUTLOOK PRICE FORECAST (2007 CONSTANT $)

FOB MINE PRICE FORECAST, $/TON

Plant Name	BASIN_ID	BASIN_NAME	MINE_STATE	REGION	FLAVOR	CODER	CODEF	BTU	PCT_SULF	GRIND	LBSO2MM	LBHGTBTU	FOB $/TON	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	COMPLIANCE, HIGH FUSION	YMC	CPH	12500	0.69	45	1.10	5.18	2007 FORECAST	$ 48.73	$ 46.20	$ 45.14	$ 43.95	$ 43.51	$ 42.58	$ 42.58	$ 44.83	$ 44.81	$ 45.79	$ 47.02	$ 48.47	$ 50.62	$ 51.41	$ 51.85	$ 52.89	$ 53.58	$ 54.95	$ 54.53	$ 53.88
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	NEAR-COMPLIANCE, HIGH FUSION	YMC	NCH	12600	1.12	44	1.78	7.44	2007 FORECAST	$ 44.89	$ 44.89	$ 44.97	$ 43.75	$ 43.22	$ 42.51	$ 42.18	$ 43.68	$ 43.02	$ 43.72	$ 44.21	$ 44.93	$ 46.63	$ 46.90	$ 47.54	$ 48.39	$ 48.60	$ 51.03	$ 51.27	$ 50.89
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	MID-SULFUR	YMC	MSZ	12300	1.75	47	2.65	10.38	2007 FORECAST	$ 42.66	$ 43.02	$ 43.64	$ 42.01	$ 41.47	$ 40.79	$ 40.43	$ 41.69	$ 41.23	$ 41.88	$ 42.22	$ 42.68	$ 44.50	$ 44.72	$ 45.29	$ 46.07	$ 46.30	$ 48.41	$ 48.42	$ 48.08
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	COMPLIANCE, HIGH FUSION	YMN	CPH	12700	0.67	45	1.06	5.18	2007 FORECAST	$ 50.01	$ 47.56	$ 47.21	$ 45.59	$ 44.98	$ 44.62	$ 44.65	$ 46.87	$ 46.61	$ 47.39	$ 48.46	$ 49.99	$ 52.26	$ 53.15	$ 53.56	$ 54.70	$ 55.46	$ 57.01	$ 56.60	$ 55.36
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	MID-SULFUR	YMN	MSZ	12100	1.74	45	2.88	10.38	2007 FORECAST	$ 45.64	$ 45.76	$ 45.80	$ 44.50	$ 43.95	$ 43.60	$ 43.50	$ 44.95	$ 44.12	$ 44.38	$ 44.79	$ 45.40	$ 46.93	$ 47.09	$ 47.95	$ 48.70	$ 49.60	$ 51.30	$ 51.20	$ 49.84
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	NEAR-COMPLIANCE, HIGH FUSION	YMN	NCH	12300	1.00	45	1.63	7.44	2007 FORECAST	$ 44.24	$ 44.01	$ 44.86	$ 43.29	$ 42.83	$ 42.52	$ 42.47	$ 44.12	$ 43.59	$ 44.19	$ 44.46	$ 44.92	$ 46.78	$ 47.17	$ 48.03	$ 48.78	$ 49.68	$ 51.38	$ 51.28	$ 49.92
COOPER	CAPP	CENTRAL APP.	TN	TENNESSEE	NEAR-COMPLIANCE, HIGH FUSION	TEN	NCH	12900	1.23	60	1.90	7.77	2007 FORECAST	$ 49.51	$ 50.24	$ 50.33	$ 49.47	$ 49.66	$ 49.47	$ 49.28	$ 49.27	$ 48.96	$ 48.76	$ 48.80	$ 49.51	$ 51.23	$ 51.50	$ 52.15	$ 53.01	$ 53.21	$ 55.68	$ 55.92	$ 55.57

RAIL DELIVERED PRICE FORECAST, $/TON

Plant Name	BASIN_ID	BASIN_NAME	MINE_STATE	REGION	FLAVOR	CODER	CODEF	BTU	PCT_SULF	GRIND	LBSO2MM	LBHGTBTU	DELVD $/TON	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	COMPLIANCE, HIGH FUSION	YMC	CPH	12500	0.69	45	1.10	5.18	2007 FORECAST	$ 58.61	$ 56.08	$ 55.02	$ 53.83	$ 53.39	$ 52.46	$ 52.46	$ 54.71	$ 54.69	$ 55.67	$ 56.90	$ 58.35	$ 60.50	$ 61.29	$ 61.73	$ 62.77	$ 63.46	$ 64.84	$ 64.41	$ 63.76
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	NEAR-COMPLIANCE, HIGH FUSION	YMC	NCH	12600	1.12	44	1.78	7.44	2007 FORECAST	$ 56.03	$ 56.03	$ 56.11	$ 54.89	$ 54.36	$ 53.65	$ 53.32	$ 54.82	$ 54.16	$ 54.86	$ 55.35	$ 56.07	$ 57.77	$ 58.04	$ 58.68	$ 59.53	$ 59.74	$ 62.17	$ 62.41	$ 62.03
DALE	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-CSX	MID-SULFUR	YMC	MSZ	12300	1.75	47	2.65	10.38	2007 FORECAST	$ 58.35	$ 58.71	$ 59.33	$ 57.70	$ 57.16	$ 56.48	$ 56.12	$ 57.58	$ 56.92	$ 57.57	$ 57.91	$ 58.57	$ 60.19	$ 60.41	$ 60.98	$ 61.76	$ 61.89	$ 64.10	$ 64.11	$ 63.77
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	COMPLIANCE, HIGH FUSION	YMN	CPH	12700	0.67	45	1.06	5.18	2007 FORECAST	$ 66.22	$ 63.77	$ 63.42	$ 61.80	$ 61.19	$ 60.83	$ 60.86	$ 63.08	$ 62.82	$ 63.60	$ 64.67	$ 66.20	$ 68.47	$ 69.36	$ 69.77	$ 70.91	$ 71.67	$ 73.22	$ 72.81	$ 71.57
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	MID-SULFUR	YMN	MSZ	12100	1.74	45	2.88	10.38	2007 FORECAST	$ 52.12	$ 52.24	$ 52.28	$ 50.98	$ 50.43	$ 50.08	$ 49.98	$ 51.44	$ 50.60	$ 50.86	$ 51.27	$ 51.88	$ 53.41	$ 53.57	$ 54.43	$ 55.18	$ 56.08	$ 57.78	$ 57.68	$ 56.32
COOPER	CAPP	CENTRAL APP.	KY	E. KY-MID BTU-NS	NEAR-COMPLIANCE, HIGH FUSION	YMN	NCH	12300	1.00	45	1.63	7.44	2007 FORECAST	$ 60.45	$ 60.22	$ 61.07	$ 59.50	$ 59.04	$ 58.73	$ 58.68	$ 60.33	$ 59.80	$ 60.40	$ 60.67	$ 61.13	$ 62.99	$ 63.38	$ 64.24	$ 64.99	$ 65.89	$ 67.59	$ 67.49	$ 66.13
COOPER	CAPP	CENTRAL APP.	TN	TENNESSEE	NEAR-COMPLIANCE, HIGH FUSION	TEN	NCH	12900	1.23	60	1.90	7.77	2007 FORECAST	$ 60.76	$ 61.49	$ 61.58	$ 60.72	$ 60.91	$ 60.72	$ 60.53	$ 60.52	$ 60.21	$ 60.01	$ 60.05	$ 60.76	$ 62.48	$ 62.75	$ 63.40	$ 64.26	$ 64.46	$ 66.93	$ 67.17	$ 66.82

APPENDIX E- REMEDIATION COST BREAKDOWN

REMEDIATION COST BREAKDOWN

Unit 1&2 Boiler Piling & Foundations			
Piling - Cubic Yards of Concrete per pier	3.14	CY	Assumes 6' diameter pile with removal of the top 3' of each pile
	x 30	piles	
Total Cubic Yards of Concrete	94		
Concrete Removal Unit Cost	$ 197.64	/CY	Means 02220-130-1220
Concrete Removal Cost	$ 18,618		
Total Concrete Volume	94	CY	
Hauling Unit Cost	$ 14.65	/CY	Means 02315-4901130
Hauling Cost	$ 1,380		Assumes 20 mile round trip
Tipping	191	tons	Assumes 150 lb/Cu Ft
Tipping Fee	$ 29.75	/ton	Demolition Disposal Service Landfill in Lexington, KY
Tipping Cost	$ 5,675		
Allowance for Asbestos Remediation	1	EA	
Unit Cost	$ 2,000,000	LS	
Total Cost	$ 2,000,000		
Total Unit 1 & 2 Boiler Removal	**$ 2,025,673**		
Unit 3&4 Boiler Piling & Foundations			
Piling - Cubic Yards of Concrete per pier	3.14	CY	Assumes 6' diameter pile with removal of the top 3' of each pile
	x 50	piles	
Total Cubic Yards of Concrete	157		
Concrete Removal Unit Cost	$ 197.64	/CY	Means 02220-130-1220
Concrete Removal Cost	$ 31,029		
Total Concrete Volume	157	CY	
Hauling Unit Cost	$ 14.65	/CY	Means 02315-4901130
Hauling Cost	$ 2,300		Assumes 20 mile round trip
Tipping	318	tons	Assumes 150 lb/Cu Ft
Tipping Fee	$ 29.75	/ton	Demolition Disposal Service Landfill in Lexington, KY
Tipping Cost	$ 9,458		
Allowance for Asbestos Remediation	1	EA	
Unit Cost	$ 3,000,000	LS	
Total Cost	$ 3,000,000		
Total Unit 3 & 4 Boiler Removal	**$ 3,042,788**		
North Ash Pond			
Removal of Potentially Contaminated Soil	13,542	CY	Assumes removal of the top 1 foot of soil from the pond bottom
Soil Removal Unit Cost	$ 7.40	/CY	Means 02315-210-6050
Total Soil Removal Cost	$ 100,208		
Number of Soil Tests	14		
Soil Test Unit Cost	$ 500	EA	
Soil Testing Cost	$ 7,000		
Earthwork - grading out pond berms	13,800	CY	Berms at an average height of 6' and an average width of 23'
Earthwork Unit Cost	$5.65	/CY	(Cut $2.84, Place/Spread $1.62, Compact $1.19)
Earthwork Cost	$ 77,970		Means 02315-452-0100, 02315-520-0020, 02315-310-5640

APPENDIX F – ECONOMIC RUNS

Exhibit 4

Project Scoping Report
Cooper Environmental Project

Cooper Power Station, Unit 2

prepared for

EAST KENTUCKY POWER COOPERATIVE

November 2008

Project No. 50198

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

Burns & McDonnell SINCE 1898

INDEX AND CERTIFICATION

East Kentucky Power Cooperative
Project Scoping Report

Project 50198

Report Index

Certification

I hereby certify, as a Professional Engineer in the state of Kentucky, that the information in the document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by East Kentucky Power Cooperative or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the Kentucky Board of Engineers and Land Surveyors under KRS 322.

STATE OF KENTUCKY
DANIEL A. FROELICH
13672
LICENSED
PROFESSIONAL ENGINEER

Daniel A Froelich

Daniel A. Froelich, P.E. KY 13672

Date: 11/10/08

FIRM REGISTRATION
Burns & McDonnell Engineering Company, Inc.
Professional Engineers
Kentucky Engineering Permit 43
Expires December 31, 2008

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EXECUTIVE SUMMARY

East Kentucky Power Cooperative (EKPC) has reached a Consent Decree Agreement with the United States Environmental Protection Agency to reduce the NOx and SO_2 emissions at the Cooper Power Station, Unit 2. The unit is located on a multi-unit site in Somerset, Kentucky.

The Cooper Power Station consists of two operating coal-fired units. The units at Cooper are Unit 1 (117 MW net) and Unit 2 (225 MW net). Both units burn bituminous coal in pulverized coal boilers.

Burns & McDonnell (B&McD) was contracted by EKPC to perform a screening analysis of alternative environmental control technologies that are feasible for use in meeting the Consent Decree requirements. The screening analysis indicated that installation of a dry circulating fluidized bed (CFB) FGD system and SCR system on Unit 2 was the lowest capital cost alternative and also offers several additional benefits for the Cooper Station.

The new control equipment will use lime as the reagent for the FGD system and ammonia with the SCR catalyst. A new fabric filter will be provided with the CFB reactor to collect the fly ash and CFB waste product for recycling back to the reactor and for disposal. The waste product will be pneumatically conveyed to the existing ash silos and two new waste product silos.

PURPOSE

The purpose of this report is to document the engineering performed during Phase 1 of the Project and describe the assumed overall scope, performance, and preliminary estimated costs of the Project.

GENERAL DESIGN

The recommended Unit 2 modifications were developed after evaluation of the major issues addressed by this report. Recommended modifications include the following:

1. Boiler exhaust gas emissions control using the following:
    a. SO_2: Addition of a dry CFB FGD system using lime as the reagent. A fabric filter will be provided downstream of the dry FGD system.
    b. NOx: Addition of a SCR system using ammonia and a catalyst along with installation of new low NOx burners and an over fire air system.
2. The existing ID fans will be replaced with new ID fans.
3. The existing primary and secondary airheaters will be replaced with a new tri-sector airheater.

4. The existing FD and PA fans will be replaced to support the draft requirements of the new airheater.
5. No improvements to the existing coal handling system are included.
6. Water supply was assumed to be from the existing low pressure lake water supply system with in-line filters to remove suspended solids.
7. Pebble lime receiving, storage and preparation (hydration) systems are included to support operation of the FGD system.
8. Aqueous ammonia (19% solution) receiving, storage and handling systems are included for use in conjunction with the SCR reactor.
9. Waste product from the FGD system and fabric filter is disposed of in on-site landfills. Waste product is transported by pneumatic conveying systems and collected in the existing ash silos and two new waste product silos.
10. Plant control is by Distributed Control System (DCS) with operator interface for the new equipment provided in an expansion of the existing DCS.
11. The electrical distribution for auxiliary power for the new environmental control systems is provided through two new 20-4.16 / 4.16 kV auxiliary transformers.
12. The existing stack will be used for exhaust of the treated flue gas.

CONTRACTING APPROACH

The recommended contracting approach for the project is a multiple contract approach. This approach provides the following benefits:

- Cost savings to EKPC in return for manageable increased Owner's risk.
- Allows early award of major equipment procurements to allow detailed design engineering to proceed expeditiously to meet the Project schedule.
- Facilitates start of construction in spring 2010 to achieve a Commercial Operation in the Spring of 2012.
- Offers the greatest flexibility for EKPC to be involved in key decisions regarding design.

In the multiple contract approach, EKPC and Burns & McDonnell work together to procure the construction and major equipment contracts. The procurement of the long lead equipment such as the fabric filters, CFB scrubber, SCR reactor and large transformers is needed early in the project to support the detailed design. The contracting approach includes 10 equipment contracts and 6 construction contracts, as referenced in Section 3 of this Report. The equipment contracts allow EKPC to reduce the cost of subcontractor markup that would be carried in the construction contracts for an alternative approach where the equipment would be included as subcontracts within those construction contracts. In addition, this approach allows EKPC more control of the quality and input into the equipment selection for the Project.

The multiple contract strategy also provides EKPC the ability to offer input into the plant design process and the opportunity to retain the fee and a portion of the contingency that would otherwise be sunk as part of alternate contracting approaches such as an engineer-procure-construct (EPC) contract margin. There is a cost to contractually transfer cost risk, schedule risk, technical risk and coordination scope to an EPC contractor. Industry experience indicates that even with a single EPC contract, the Owner still carries the overall responsibility for the project, including many of the risks that are expected to be transferred to the EPC contractor, when this form of contracting is employed. On some recent EPC projects, contractors have declined to take the labor risk.

This project involves a significant amount of retrofit work in the existing plant. It is anticipated that the scope of work will increase as many unknown conditions are discovered during the project. An EPC contracting approach provides less flexibility than the multiple contract contracting strategy when dealing with unknown conditions associated with the retrofit work.

SCHEDULE

A level 2 project schedule was prepared and is included in Section 4. The project schedule is driven by the need to place the Unit 2 environmental controls into service by June 2012. The suggested preliminary schedule is based on a detailed engineering start date in November 2008 and substantial completion of the major control systems in May 2012. A major outage will be needed for Unit 2 in the spring of 2012 to accomplish the tie in of the ductwork, electrical and piping systems. The following table lists the suggested milestone dates for the Project.

Table ES.1
Suggested Project Key Milestone Dates

Milestone	Milestone Date
Start Design Engineering	November 2008
Issue Contract C1310 – FGD System Bid Package	February 2009
Award Contract C1310 – FGD System	August 2009
Issue Contract C1330 - SCR Bid Package	March 2009
Award Contract C1330 – SCR	August 2009
Start Construction	April 2010
Mechanical Construction Substantial Completion	February 2012

Electrical Construction Substantial Completion	March 2012
FGD System Substantial Completion	May 2012
SCR Substantial Completion	May 2012

COST ESTIMATE

The estimated capital cost for the Cooper Unit 2 Environmental Project is approximately $324 Million including escalation for commercial operation in mid 2012 for Unit 2. This estimated capital cost does not include upgrades to the water supply system, coal handling system, a new stack or repairs or modifications to the existing stack, switchyard and transmission line; demolition of the abandoned Unit 2 electrostatic precipitator, primary air heater, secondary air heaters, PA fans, FD fans, and ID fans; taxes including sales, use, gross receipts, and property; all insurance other than General Liability including but not limited to builder's risk and E&O insurance; abatement for asbestos, lead paint and contaminated soils; sound abatement above normal supply; aesthetic landscaping; high escalation associated with extreme market conditions; financing fees and interest during construction.

Labor was assumed to be union labor for the cost estimate. To account for the retrofit aspect of the project, a Project Definition contingency of approximately $25 Million is included in this estimate, equating to 10% of the estimated capital cost. In addition to the Project Definition contingency, a 15% Estimate Accuracy contingency of approximately $38 Million is included to cover the accuracy of pricing and commodity estimates for the scope defined in this report.

* * * * *

1.0 INTRODUCTION

1.1 PROJECT BACKGROUND

EKPC has reached agreement on a Consent Decree with the United States Environmental Protection Agency to reduce the NOx and SO_2 emissions at the Cooper Power Station, Unit 2. EKPC is considering adding selective catalytic reduction (SCR) and flue gas desulfurization (FGD) systems at the Company's Cooper Power Station. The Cooper Unit 2 is a 225 MW net capacity coal-fired unit. The unit is located on a multi-unit site in Somerset, Kentucky. The unit has an existing electrostatic precipitator that was installed for removal of particulates in the flue gas.

The Consent Decree requires that the NOx control system reduce Unit 2 NOx outlet emissions to 0.080 lb NOx/mmBtu. It also requires that the Unit 2 SO_2 emissions be reduced to 0.100 lb SO_2/mmBtu or a reduction of 95% of the inlet SO_2.

EKPC contracted with Burns & McDonnell to prepare various preliminary design documents, a project schedule and perform a cost estimate for the preferred equipment and systems required to meet the Consent Decree.

1.2 PROJECT SCOPING REPORT

The project scoping report includes results of the preliminary evaluation of the following major items:

1. Flue Gas Desulfurization
2. Selective Catalytic Reduction
3. Boiler Modifications
4. Waste Product Handling System
5. Fans
6. Electrical Loads
7. Integration of Project Controls with Existing DCS
8. Equipment and Ductwork Layout
9. Constructability
10. Contracting Approach
11. Engineering and Construction Schedule
12. Preliminary Capital Cost Estimate

1.3 OBJECTIVES

The objectives of the Phase 1 engineering for the Cooper Environmental Project were to define preliminary design parameters of major components of the project and provide adequate information to support the following activities:

1. Evaluation of the economics of the major technology components.
2. Development of a preferred contracting approach.
3. Preparation of a preliminary project schedule.
4. Project cost estimate for the Cooper Unit 2 Consent Decree equipment.

1.4 LIMITATIONS AND QUALIFICATIONS

Estimates and projections prepared by Burns & McDonnell relating to schedules, performance, construction costs, and operating and maintenance costs are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by Burns & McDonnell.

1.5 TECHNOLOGY ALTERNATIVE SCREENING SUMMARY

Preliminary design and an assessment of the scope of systems and equipment was performed for the following environmental requirements that may need to be met by the Project:

1.5.1 Consent Decree

The Consent Decree (CD) requires installation of a FGD system on Cooper 2, to achieve a 30-day rolling average SO_2 emissions rate below 0.100 lbs/mmBtu or 95% SO_2 removal rate before June 30, 2012, and a SCR system on Cooper 2 to achieve a 30-day rolling average NOx emissions rate below 0.080 lbs/mmBtu before December 31, 2012. (For each alternative, systems must be on-line 30 days prior to compliance date in order to establish the first 30 day average.) Since Cooper Station Unit 1 and Unit 2 could not achieve a particulate emission rate of 0.030 lb/mmBtu, the CD required EKPC to perform a Pollution Control Upgrade Analysis (PCUA) to determine what equipment upgrades are required and the associated particulate emission. The results of the PCUA determined that the applicable filterable particulate emission rates for Cooper Station Unit 1 and Unit 2 are 0.15 lb/mmBtu and 0.13 lb/mmBtu respectively. These emission limits become effective one year after EPA approval of the PCUA.

1.5.2 Consent Decree plus Best Available Retrofit Technology

In addition to the requirements of the CD, Cooper Units 1 and 2 are also subject to the requirements for Best Available Retrofit Technology (BART) as defined in the "Regional Haze State Implementation Plan for Kentucky's Class I Area" (KY RH SIP). The KY RH SIP establishes BART for PM for Cooper Units 1 and 2 as "install a wet FGD and wet ESP that will address condensable particulate emissions and other visibility impairing pollutants". The corresponding BART PM emission limit is a filterable PM emission rate of 0.030 lb/mmBtu. This emission limit becomes effective no later than five years after EPA approval of the KY RH SIP. The BART modeling demonstration was based on a PM (filterable) emission rate of 0.030 lb/mmBtu and a PM (total including condensables) emissions rate of 0.052 lb/mmBtu.

1.5.3 Best Available Control Technology and Maximum Achievable Control Technology

Hypothetical future requirements for Cooper Station to meet requirements of Best Available Control Technology (BACT) may potentially require additional emission reductions beyond those required by the CD or the KY RH SIP. Burns & McDonnell estimates that BACT may require the installation of an FGD system for flue gas from Cooper 1 and 2 that will achieve a 30-day rolling average SO_2 emissions rate below 0.07 lb/mmBtu or 98% removal for SO_2, and an SCR for Unit 1 that would limit a 30-day rolling average NOx emissions rate to 0.07 lb/mmBtu or less. In addition, BACT may require the installation of a WESP or equivalent PM emissions control measures on Cooper 1 and 2 that will achieve a filterable PM emissions rate below 0.015 lb/mmBtu, and controls that will limit H_2SO_4 emissions to 0.005 lb/mmBtu or less. The options should allow Cooper 2 to be controlled for NOx and SO_2 before June 30, 2012 with Cooper 1 to be controlled under the same compliance limits before January 1, 2015. Cooper Station may be required to achieve mercury removal of 90% for Cooper 1 and 2 to meet Maximum Achievable Control Technology (MACT) before June 30, 2012.

1.5.4 Screening Process

A screening process was completed to evaluate potential combinations of environmental control technologies that were considered to be feasible to provide the performance required and that also were in operation at other facilities with sufficient experience to confirm their viability for long term successful operation. Qualifying technologies were screened by performing a differential economic analysis to identify the potential differences in the capital and life cycle costs for each technology. The screening analysis did not include Unit 1 as the environmental requirements for that unit are not defined at this time.

Several combinations of technologies were evaluated for the various environmental requirement alternatives that were defined by EKPC. The technologies considered included wet FGD, dry circulating fluidized bed (CFB) FGD, SCR, sorbent injection, wet electrostatic precipitators (ESP), fabric filters and the existing dry ESPs.

The alternative combinations of environmental technologies that were evaluated during the screening process are listed on the Table 1.1.

TABLE 1.1 - Screening Study Options

Description	CD and BART (Dry FGD)	CD and BART (Wet FGD)	CD and BART (Wet FGD and Wet ESP)
NOx Control	SCR – Unit 2	SCR – Unit 2	SCR – Unit 2
SO_2 Control	Dry Lime CFB	Wet Limestone FGD	Wet Limestone FGD
SO_3 Control	Dry Lime CFB	Sorbent Injection	Wet ESP
Particulate Control	Fabric Filter	Existing Dry ESP / Wet FGD	Existing Dry ESP / Wet FGD and Wet ESP

1.6 SELECTED ALTERNATIVE

All of the environmental control equipment options listed in Table 1.1 were evaluated to have the capacity to meet the requirements of the Consent Decree. In addition, they were judged to also have the potential to meet the requirements that might be put in place to meet the BART, BACT and MACT regulations when they are issued. Therefore, all options were considered to have equal capability to perform as required to meet the current and future regulatory NOx, SOx, PM and mercury requirements.

A screening level economic analysis of all of the environmental options was performed to determine the differential capital and life cycle cost of each option. The dry FGD option was estimated to have the lowest capital cost of all of the options and was selected by EKPC as the preferred option to proceed with for the project. The selected option includes a dry CFB scrubber using pebble lime that is converted into hydrated lime and used as the SO_2 removal reagent. A fabric filter, which replaces the existing electrostatic precipitator, is included to remove and recycle fly ash and reagent. An SCR system is included to remove NOx from the flue gas. Low NOx burners and overfire air will also be installed in conjunction with the SCR addition to reduce the NOx inlet concentration to the SCR and reduce operating costs.

Concurrent with the screening analysis of various environmental options, a study was performed by the boiler original equipment manufacturer to determine the impact on the boiler system of burning a range of coals including several higher sulfur content coals. This study also evaluated the operation of the boiler with respect to maintaining minimum temperatures at the economizer outlet that will be needed to allow for good operation of the SCR. Modifications were identified to be made to the economizer, superheater, reheater and air heater that should be made when the SCR is installed. These modifications were included in the selected alternative. The scope of this work and costs are included in this report.

* * * * *

2.0 PROJECT SCOPE

2.1 PROCESS FLOW DIAGRAMS

Five process flow diagrams are included with the report; Overall AQCS Process, Ammonia System, Lime System, Ash Handling System and Water System. Exhibit 1 shows the overall air quality control system (AQCS) process, which includes the FD Fans, PA Fans, Tri-sector Air Heater, Selective Catalytic Reduction (SCR) system, CFB Scrubber, Fabric Filter, and ID Fans.

The remaining four process flow diagrams show the supporting systems for the AQCS process. Exhibit 2 shows the aqueous ammonia system, which stores, feeds, vaporizes and injects 19% aqueous ammonia into the flue gas upstream of the SCR. Exhibit 3 shows the lime system which stores, feeds, hydrates and injects lime into the CFB scrubber and the lime dust system which feeds lime onto the coal supply conveyor for control of arsenic in the flue gas produced in the combustion process.

Exhibit 4 shows the ash handling system, which withdraws waste material/ash from the SCR Reactor and CFB Scrubber, transports it to the ash silos and prepares it for disposal at the ash landfill. The actual details for this system will be finalized during Phase 2 due to the complications of integrating the new waste/ash streams while retaining the existing Unit 1 fly ash stream.

Exhibit 5 shows the water system to support the new AQCS. The current philosophy is to filter existing Low Pressure Lake Water Return for use in the lime hydrators and for CFB Lance water. The Dry CFB scrubber vendors include a Lance Water tank in their scope of work.

2.2 AQCS GENERAL ARRANGEMENT

A preliminary general arrangement for the Cooper Unit 2 Environmental Project was developed and is included at the end of this section.

Since the project is the retrofit of new AQCS equipment to an existing unit, the layout is influenced by existing structures, access, constructability, costs and consideration of minimizing outage time during construction.

Maintenance access and crane access are significant influences on the equipment arrangement. Road access from the north between the AQCS equipment and the coal yard and along the south of the AQCS equipment should be provided for crane and truck access. The intent is to provide a minimum of 30 feet clear to bring in a large crane for construction and future maintenance. An area south of the SCR reactor is available for a crane to be located. The ID fans, fabric filter and scrubber are located farther east than necessary to route ductwork so that a north-south access road can be provided for bottom ash load out, ID fan maintenance, and SCR catalyst removal/installation.

The layout began with the preliminary sizing of the major equipment and locating the equipment in the available area east of the Unit 2, west of the existing coal pile, and north of the existing circulating water pipelines. Equipment vendors provided initial equipment sizing for the fabric filter, CFB scrubber equipment and storage silos. The induced draft fan size is based on a similar project. The SCR reactor and ductwork sizing is based on estimated gas flows and acceptable gas flow velocities.

Multiple locations of the SCR reactor were evaluated. Locating the SCR reactor over the existing precipitator area would be difficult. The existing precipitators would need to stay in service during the initial construction of the reactor. A reactor support structure spanning over the existing precipitator would be required. Adequate space west of the precipitator is not available for SCR support columns and foundations. Another option with the SCR reactor located in the precipitator area would be to demolish the existing precipitator after installation of the new fabric filter and constructing the SCR reactor in the precipitator area. This option is not feasible due to schedule constraints. The location selected has the SCR reactor and new tri-sector air heater located directly east of the existing boiler structure. With this location, adequate space is available for support foundations and support steel. The SCR reactor and air heater will be constructed with the plant in operation. Ductwork located in the existing precipitator and boiler areas will be constructed during the final tie-in outage. With this arrangement, the ductwork from the economizer will be routed out the east side of the boiler enclosure to the inlet of the SCR reactor. The ductwork from the SCR reactor outlet will be routed through a new tri-sector air heater and then to the new CFB scrubber inlet. New primary air fans and forced draft fans will be located under the SCR reactor and new air heater. Ductwork from the FD fan exhaust will be routed to the tri-sector air heater and then back to the existing boiler wind box inlets. A new seal air pipe will be routed from the FD fan outlet duct back to the existing seal air pipe located in the existing FD area. Ductwork will be routed from the FD fan outlet ductwork to the PA fan inlets. Ductwork from the PA fan exhaust will be routed to the tri-sector air heater and then back to the existing primary air ductwork. A tempering air duct will also be routed from the PA fan outlet duct back to the existing tempering air ductwork. New steam air preheaters will be provided directly upstream of the forced draft and primary air inlets to the air heater.

The location selected for the CFB scrubber, lime silos, fabric filter, electrical power control module enclosure (PCM), induced draft fans and induced draft fan VFD enclosure is east of the existing Unit 2, existing bottom ash load out facility and SCR reactor; north of the existing circulating water piping; and south of the existing coal supply conveyor. Ductwork will be routed from the new tri-sector air heater outlet located under the SCR reactor to the CFB scrubber inlet duct located at the bottom of the scrubber vessel. The scrubber outlet is at the top of the vessel and a short ductwork section will be provided between the scrubber outlet and the fabric filter inlet located on the east face of the fabric filter. Ductwork will be routed from the fabric filter outlet located on the west face of the fabric filter to the ID fan inlets. The ID fans will discharge into ductwork that is routed to the existing Unit 2 chimney inlet. This ductwork will be routed directly north of the SCR reactor and through the precipitator area along the existing chimney inlet ductwork routing. The PCM will house the switchgear, MCC's, DCS cabinets and UPS that will be provided for the new environmental equipment.

The existing grade in the project area is generally flat in the SCR reactor and ID fan area. The grade slopes beginning in the area of the fabric filter up to the coal pile storage area. The area north of the coal conveyor is also higher than the area to the south with the change in grade located under the coal conveyor. A steep slope down to the river begins directly south of the circulating water pipelines. The intent is to grade the site by cutting into the existing hill in the fabric filter and scrubber area to avoid or minimize stepping of the finish grade in the AQCS equipment areas. Care in grading the site must be taken so that existing conveyor foundations are not undermined, suitable road grades are provided, adequate cover is maintained over the circulating pipelines, and maintenance access is provided around the equipment. Preliminary review of the site grading indicates that the project area can be adequately graded.

2.3 ELECTRICAL ONE-LINE

An electrical one-line has been included with this report that shows the major electrical modifications required to provide power to the new emissions control equipment on Cooper Unit 2. The modifications include the installation of a new Generator Circuit Breaker (GCB) between the main power transformer and the steam turbine generator along with two new 3-winding auxiliary transformers that replace the existing auxiliary transformers. The new auxiliary transformers will feed the existing Unit 2 switchgear from the secondary winding and will feed the new emission control equipment from the tertiary winding. The new electrical equipment provided for powering the emissions control equipment includes 4160V switchgear, 480V switchgear, 4160/480V transformers, 480V MCC's, UPS and ID Fan VFD's.

2.4 CONTROL SYSTEM ARCHITECTURE

The new Unit 2 FGD system will be controlled and monitored by expanding the existing plant DCS control system and adding new DCS process controller's along with remote I/O in a new FGD electrical building. New operator workstations will be installed to operate the ID Fans and scrubber equipment from the main plant control room.

The DCS will utilize a combination of hard wired I/O and communications to interface to the scrubber equipment. For equipment with dedicated controller's, common communication interfaces will be utilized for supervisory monitoring and control. Fiber optic media will be implemented for most communication networks.

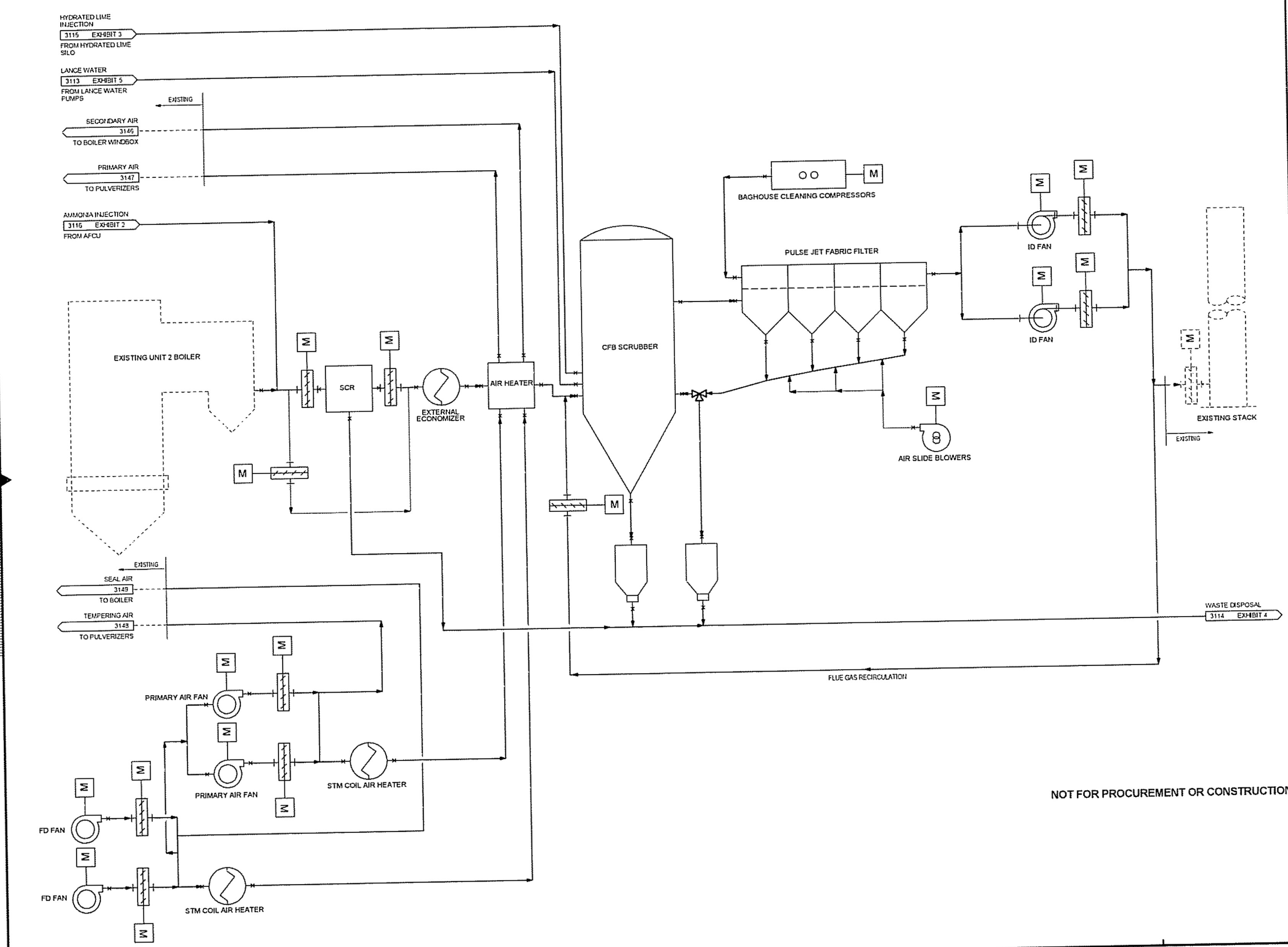
Transmitters in lieu of switches will be utilized where possible, with minimal discrete operated instruments. Where flow transmitters are required magnetic meters will be specified to limit additional freeze protection equipment. Local gauges will be utilized to provide information local to the equipment. Local gauges will be used to indicate level, pressure, or temperature. Balance of plant instruments not provided under one of the major system furnish contracts, will be procured with the mechanical installation contract.

The new Unit 2 FGD system will require emissions monitoring for both scrubber inlet and outlet. Inlet monitoring will be limited to SO_2 and CO_2 and outlet monitoring will require SO_2, NOX, CO_2, flow, and opacity. The existing DAS will be modified to include reporting for the new equipment. Unit 1 will require particulate monitoring and will be installed on the Unit 1 duct work upstream of the stack.

2.5 MAJOR EQUIPMENT LIST

An Equipment List is included which lists major equipment for the project. The list is based on information provided by Babcock Power Environmental.

* * * * *



NOT FOR PROCUREMENT OR CONSTRUCTION

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B	10-27-08	MDF		ISSUED WITH DRAFT PROJECT SCOPING REPORT
C	11-07-08	MDF	JLY	ISSUED WITH FINAL PROJECT SCOPING REPORT

Burns & McDonnell
SINCE 1898

date: Sep 30, 2008
detailed: M FRIEDEL
designed: M FRIEDEL
checked:

EAST KENTUCKY POWER COOPERATIVE

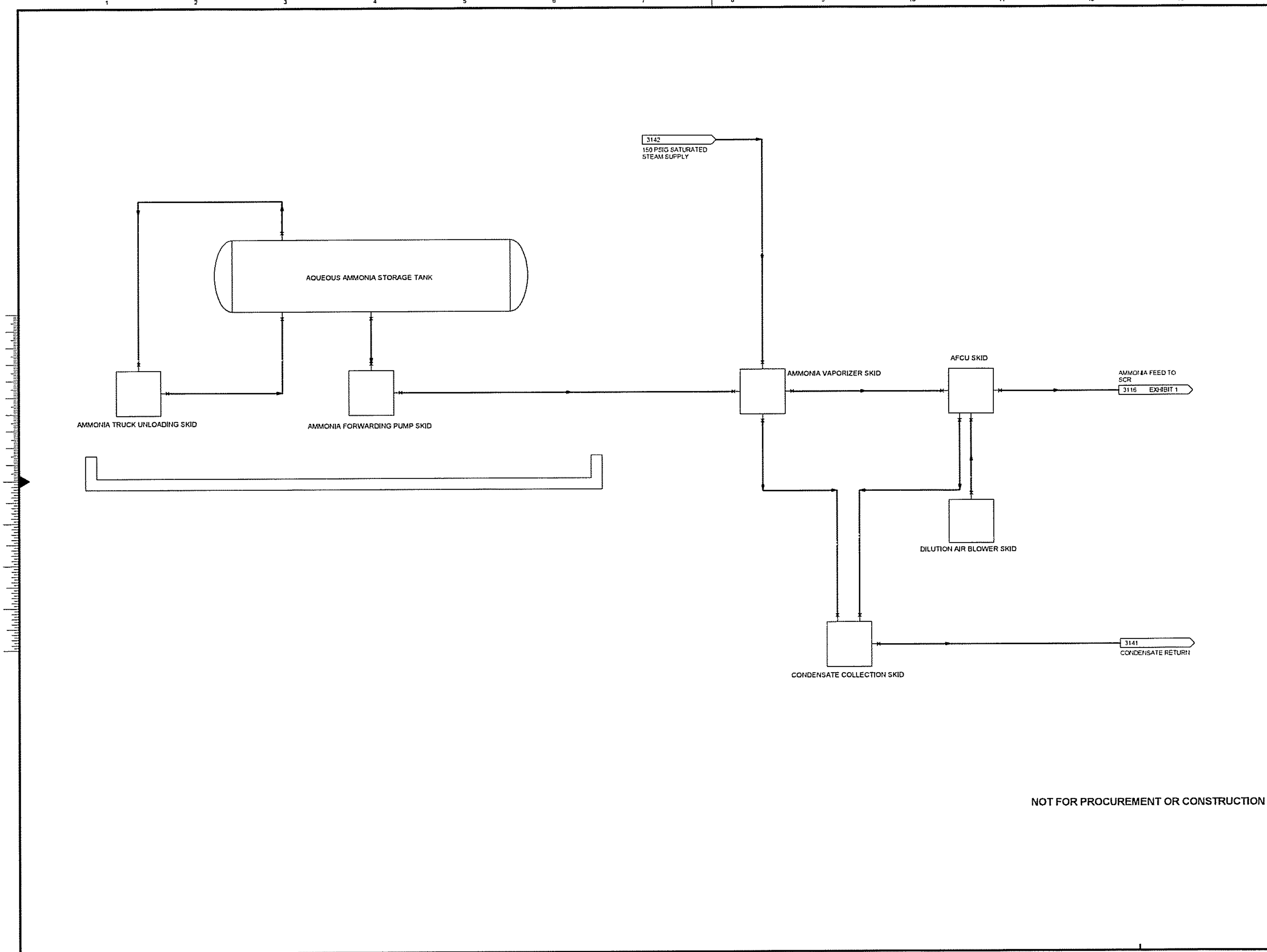
Process & Instrumentation Diagram
EKPC AQCS Flow Diagram

project: 50198
contract:

drawing: **Exhibit 1** — rev. **C**

sheet of sheets

file \TRAINING\50198 Exhibit 1.pid



NOT FOR PROCUREMENT OR CONSTRUCTION

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C	11-07-08	MDF	JLY	ISSUED WITH FINAL PROJECT SCOPING REPORT

Burns & McDonnell SINCE 1898

date: Oct 14, 2008
detailed: M FRIEDEL
designed: M FRIEDEL
checked:

EAST KENTUCKY POWER COOPERATIVE

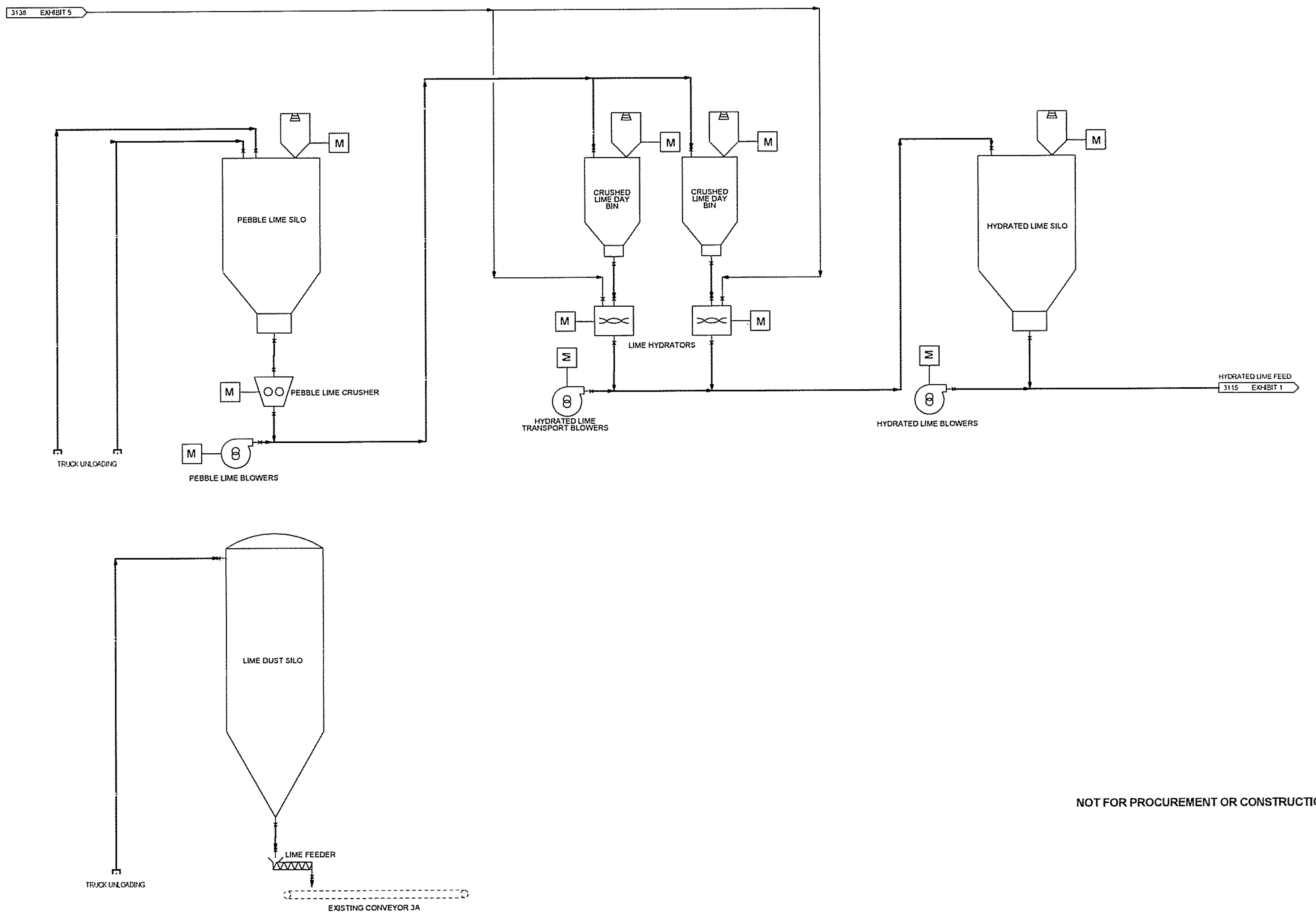
Process & Instrumentation Diagram
EKPC Ammonia Flow Diagram

project: 50198
contract:

drawing: **Exhibit 2** — rev. **C**

sheet of sheets

file \TRAINING\50198 Exhibit 2.pid



NOT FOR PROCUREMENT OR CONSTRUCTION

no.	date	by	chd	description
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C	11-07-08	MDF	JLY	ISSUED WITH FINAL PROJECT SCOPING REPORT

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date: Oct 09, 2008	detailed: M FRIEDEL
designed: M FRIEDEL	checked:

EAST KENTUCKY POWER COOPERATIVE

Process & Instrumentation Diagram
EKPC Lime Flow Diagram

project: 50198	contract:	
drawing: Exhibit 3	—	rev. C
sheet	of	sheets

file \TRAINING\50198 Exhibit 3.pid

no.	date	by	chd	description
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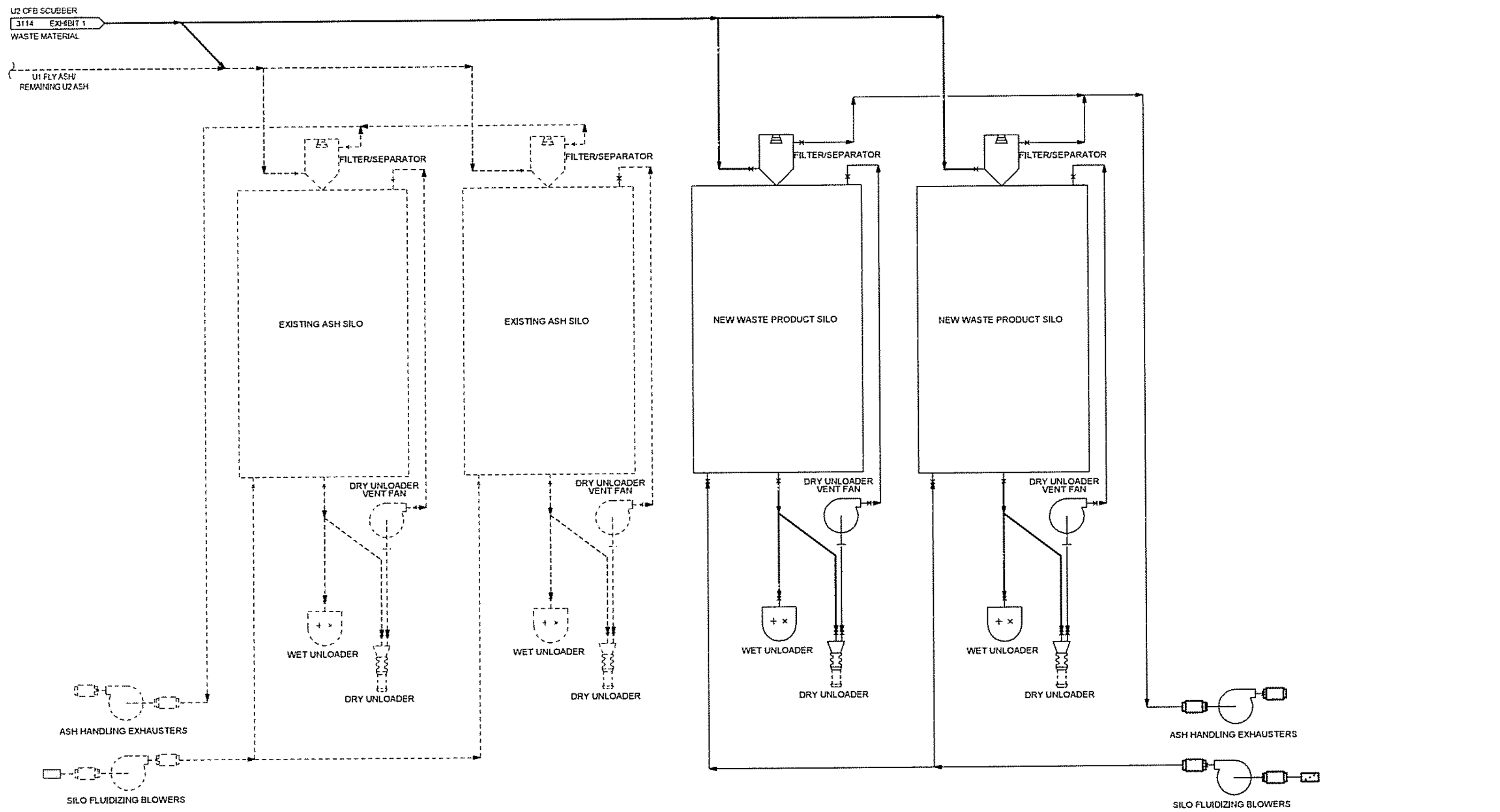
B	10-27-08	MDF		ISSUED WITH DRAFT PROJECT SCOPING REPORT
C	11-07-08	MDF	JLY	ISSUED WITH FINAL PROJECT SCOPING REPORT



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date	detailed
Oct 10, 2008	M FRIEDEL
designed	checked
M FRIEDEL	

EAST KENTUCKY POWER COOPERATIVE

Process & Instrumentation Diagram
EKPC Waste Hdlg Flow Diagram

project 50198 | contract

drawing **Exhibit 4** — rev. **C**

sheet of sheets

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no.	date	by	chd	description
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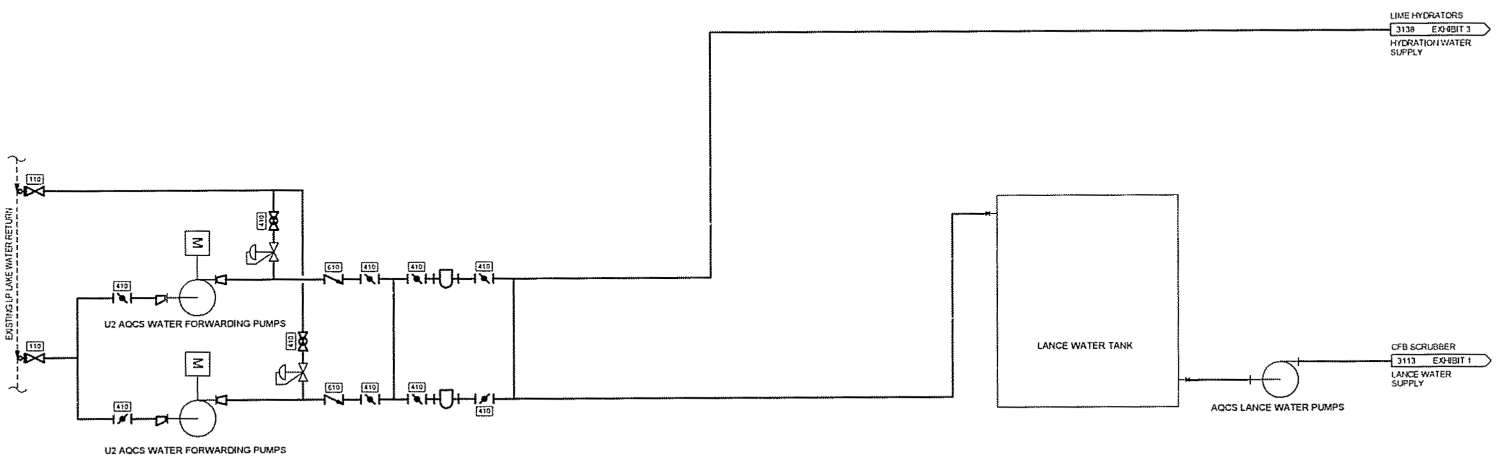
	11-07-08	MDF	JLY	ISSUED WITH FINAL PROJECT SCOPING REPORT



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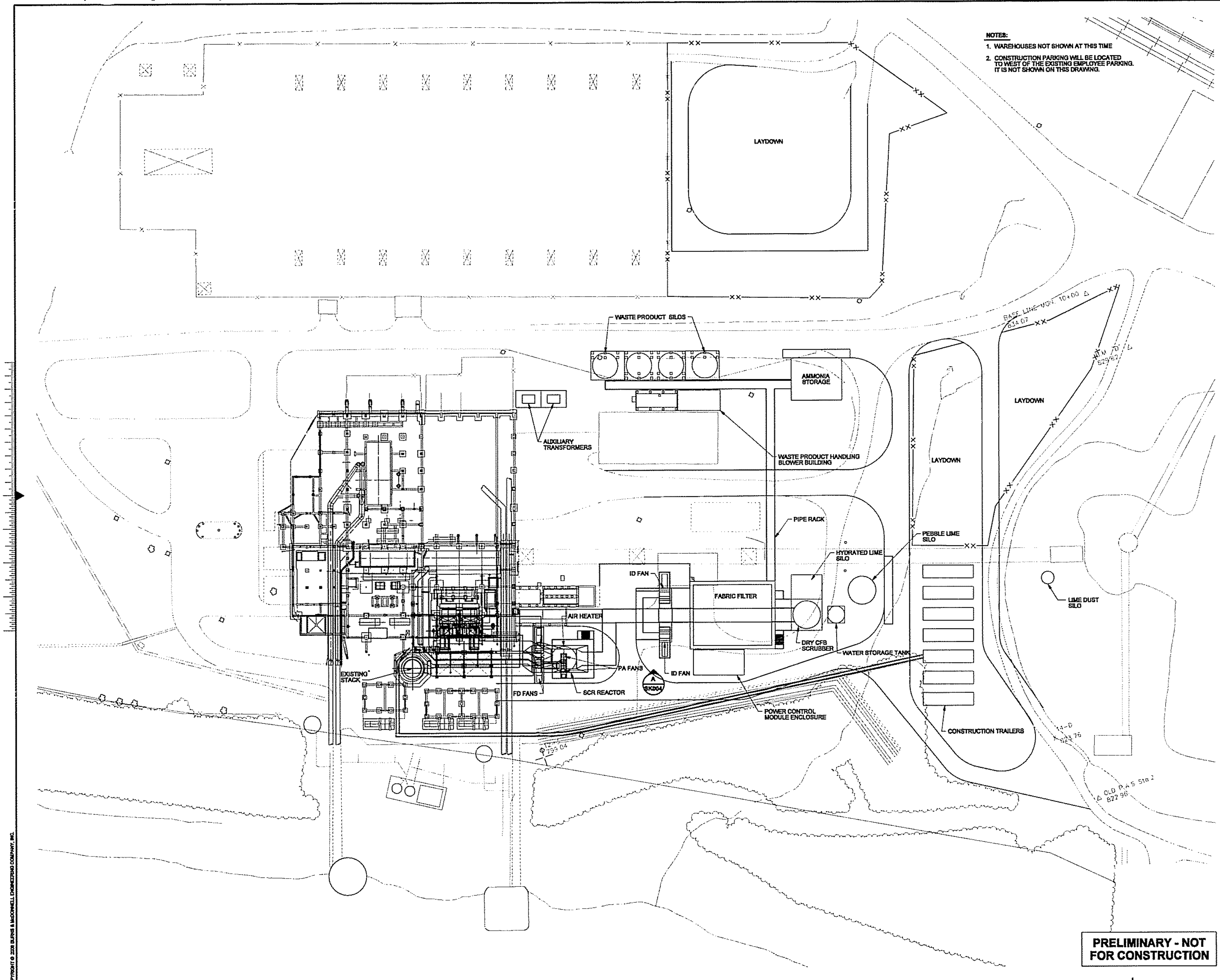
date: Oct 10, 2008	detailed: M FRIEDEL
designed: M FRIEDEL	checked:

EAST KENTUCKY POWER COOPERATIVE

Process & Instrumentation Diagram
EKPC AQCS Water Flow Diagram

project: 50198	contract:
drawing: **Exhibit 5** —	rev.: **C**
sheet:	of sheets:

file: \TRAINING\50198 Exhibit 5.pid



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C	11/10/08	RNO	MDB	ISSUED WITH FINAL PROJECT SCOPING REPORT

Burns & McDonnell

date: OCTOBER 10, 2008	detailed: R. OWENS
designed: R. OWENS	checked: M. BLEYTHING

EAST KENTUCKY POWER COOPERATIVE

COOPER STATION

UNIT 2 AQCS
PRELIMINARY GENERAL ARRANGEMENT

project: 50196	contract:
drawing: CS002	rev.: — C
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11/10/2008

no.	date	by	ckd	description
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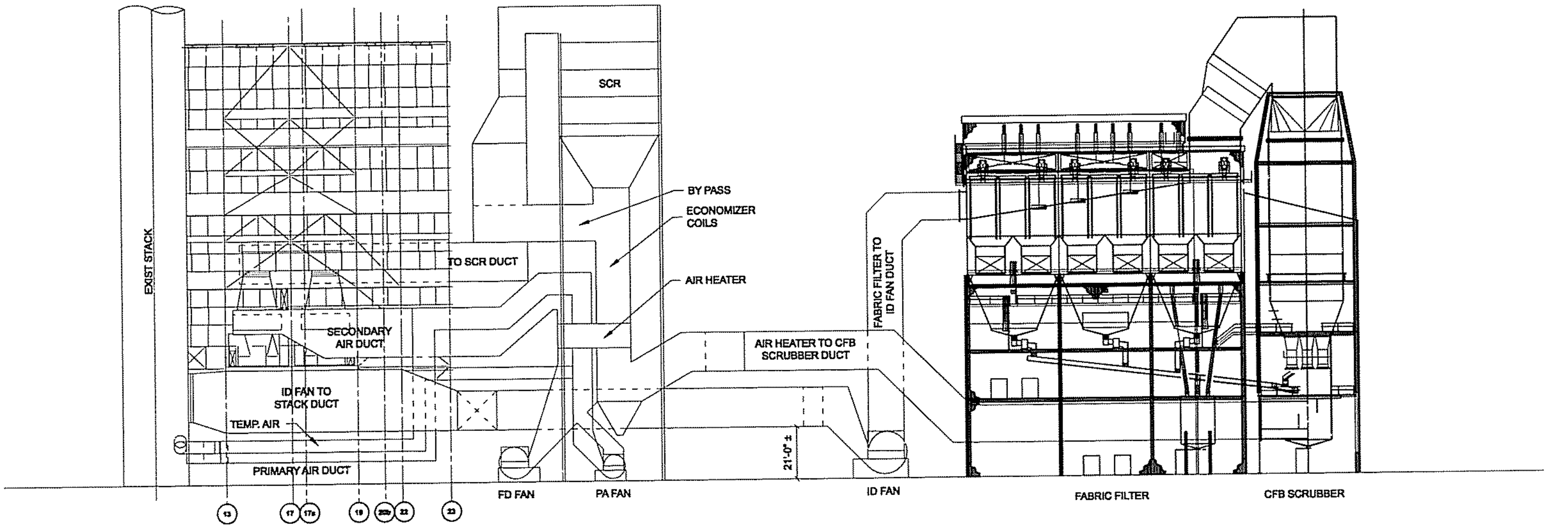

ELEVATION
LOOKING NORTH
A
CS001

Burns & McDonnell

date OCTOBER 13, 2008	detailed S. LAWSON
designed S. LAWSON	checked R. OWENS

EAST KENTUCKY POWER COOPERATIVE

COOPER STATION

UNIT 2 AQCS
ELEVATION

project 50198	contract
drawing SK004	rev. — C
sheet	of sheets

file 50198SK004

11/10/2008

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no.	date	by	ckd	description
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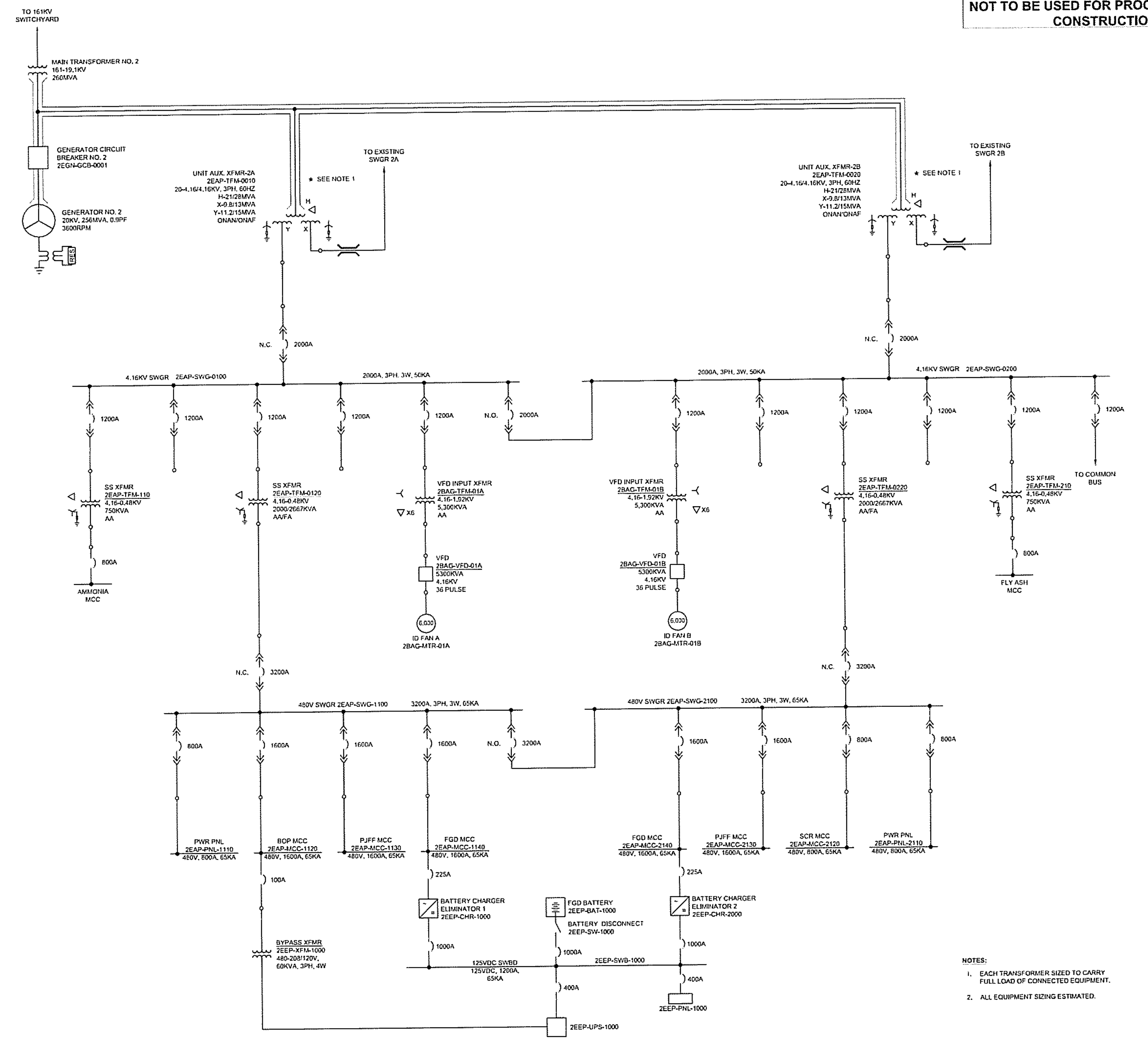
B	10/27/08	CBR	–	ISSUED WITH DRAFT PROJECT SCOPING REPORT
C	11/5/08	CBR	–	ISSUED WITH FINAL PROJECT SCOPING REPORT



NOTES:

1. EACH TRANSFORMER SIZED TO CARRY FULL LOAD OF CONNECTED EQUIPMENT.
2. ALL EQUIPMENT SIZING ESTIMATED.

Burns & McDonnell

date 10-15-08	detailed C. RUCKMAN
designed C. RUCKMAN	checked

EAST KENTUCKY POWER COOPERATIVE

COOPER STATION

ELECTRICAL ONE-LINES
AQCS OVERALL ONE-LINE

project 50198	contract
drawing 2EE001	rev. – C
sheet	of sheets

file 501082EE001

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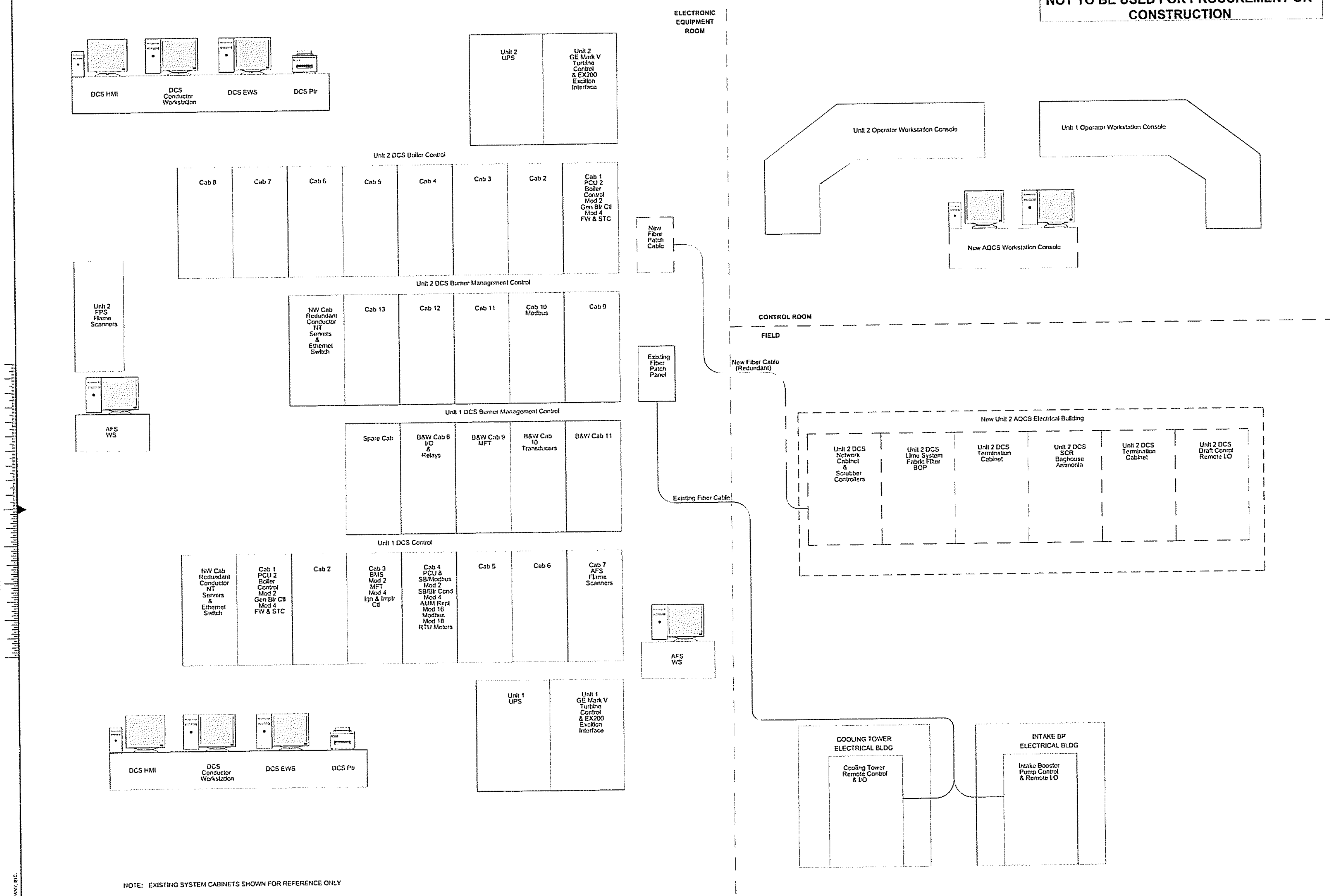

NOTE: EXISTING SYSTEM CABINETS SHOWN FOR REFERENCE ONLY

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B	10/22/08	DN	–	ISSUE FOR REVIEW
C	10/27/08	DN	–	ISSUED WITH DRAFT PROJECT SCOPING REPORT
D	11/07/08	DN	–	ISSUED WITH FINAL PROJECT SCOPING REPORT

Burns & McDonnell

date 10-17-08
detailed D. NIENHUESER
designed D. NIENHUESER
checked

EAST KENTUCKY POWER COOPERATIVE

COOPER STATION

EKPC COOPER STATION
AQCS Project
Conceptual Controls Design

project 50198
contract

drawing **SK-100** rev. **– D**

sheet of sheets

file SK-100.DWG

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EQUIPMENT LIST

EKPC Cooper 2 AQCS
B&McD Project No. 50198

Rev No.	Date	Prepared By	Checked By
A	10/20/2008	M FRIEDEL	
B	10/27/2008	M FRIEDEL	

Equipment Tag	Equipment Description	Furnish By	Install By	P&ID Name	Remarks
2BAG-DPR-003A	ID Fan A Isolation Damper	1310	1310		
2BAG-DPR-003B	ID Fan B Isolation Damper	1310	1310		
2BAG-DPR-005	AQCS Flue Gas Recirculation Damper	1310	1310		
2BAG-FAN-003A	ID Fan A	1310	1310		
2BAG-FAN-003B	ID Fan B	1310	1310		
2BAG-SKD-003A	ID Fan A Lube Oil Skid	1310	1310		
2BAG-SKD-003B	ID Fan B Lube Oil Skid	1310	1310		
2BAG-VFD-003A	ID Fan A VFD	1310	1310		
2BAG-VFD-003B	ID Fan B VFD	1310	1310		
2GSA-ABS-002	CFB Scrubber	1310	1310		
2GSA-BGS-001	Baghouse	1310	1310		
2GSA-BLR-001	Air Slide Blower 1	1310	1310		
2GSA-BLR-002	Air Slide Blower 2	1310	1310		
2GSA-BLR-003	Air Slide Blower 3	1310	1310		
2GSA-BLR-004	Ash Surge Bin Fluidizing Blower	1310	1310		
2GSA-CNV-001	Air Slide 1	1310	1310		
2GSA-CNV-002	Air Slide 2	1310	1310		
2GSA-CRS-001	CFB Scrubber Ash Crusher 1	1310	1310		
2GSA-CRS-002	CFB Scrubber Ash Crusher 2	1310	1310		
2GSA-SLO-001	Ash Surge Bin 1	1310	1310		
2GSA-SLO-002	Ash Surge Bin 2	1310	1310		
2GSH-BGS-001	Hydrator 1 Baghouse	1310	1310		
2GSH-BGS-002	Hydrator 2 Baghouse	1310	1310		
2GSH-BLR-001	Pebble Lime Silo Bin Vent Filter Blower	1310	1310		
2GSH-BLR-002A	Pebble Lime Blower 1	1310	1310		
2GSH-BLR-002B	Pebble Lime Blower 2	1310	1310		
2GSH-BLR-003	Crushed Lime Day Bin 1 Bin Vent Filter Blower	1310	1310		
2GSH-BLR-004	Crushed Lime Day Bin 2 Bin Vent Filter Blower	1310	1310		
2GSH-BLR-005	Hydrator 1 Baghouse Blower	1310	1310		
2GSH-BLR-006A	Hydrator 1 Transport Blower A	1310	1310		
2GSH-BLR-006B	Hydrator 1 Transport Blower B	1310	1310		
2GSH-BLR-007	Hydrator 2 Baghouse Blower	1310	1310		
2GSH-BLR-008A	Hydrator 2 Transport Blower A	1310	1310		
2GSH-BLR-008B	Hydrator 2 Transport Blower B	1310	1310		
2GSH-BLR-009	Hydrated Lime Silo Bin Vent Filter Blower	1310	1310		
2GSH-BLR-010A	Hydrated Lime Silo Aeration Blower 1	1310	1310		
2GSH-BLR-010B	Hydrated Lime Silo Aeration Blower 2	1310	1310		
2GSH-BLR-011	Hydrated Lime Vent Hopper Bin Vent Filter Blower	1310	1310		
2GSH-BLR-012A	Hydrated Lime Blower 1	1310	1310		
2GSH-BLR-012B	Hydrated Lime Blower 2	1310	1310		
2GSH-CRS-001	Pebble Lime Crusher 1	1310	1310		
2GSH-CRS-002	Pebble Lime Crusher 2	1310	1310		
2GSH-FDR-001	Pebble Lime Silo Activator	1310	1310		
2GSH-FDR-002A	Hydrator 1 Screw Feeder 1	1310	1310		
2GSH-FDR-002B	Hydrator 1 Screw Feeder 2	1310	1310		
2GSH-FDR-003A	Hydrator 2 Screw Feeder 1	1310	1310		
2GSH-FDR-003B	Hydrator 2 Screw Feeder 2	1310	1310		
2GSH-FDR-004	Hydrator 1 Discharge Feeder	1310	1310		
2GSH-FDR-005	Hydrator 2 Discharge Feeder	1310	1310		
2GSH-FLT-001	Pebble Lime Silo Bin Vent Filter	1310	1310		
2GSH-FLT-002A	Crushed Lime Day Bin 1 Bin Vent Filter	1310	1310		
2GSH-FLT-002B	Crushed Lime Day Bin 2 Bin Vent Filter	1310	1310		
2GSH-FLT-003	Hydrated Lime Silo Bin Vent Filter	1310	1310		
2GSH-FLT-004	Hydrated Lime Vent Hopper Bin Vent Filter	1310	1310		
2GSH-HOP-001	Hydrated Lime Vent Hopper	1310	1310		
2GSH-MXR-001	Hydrator 1	1310	1310		
2GSH-MXR-002	Hydrator 2	1310	1310		
2GSH-PMP-001	Hydrator 1 Water Pump	1310	1310		
2GSH-PMP-002	Hydrator 2 Water Pump	1310	1310		
2GSH-SLO-002A	Crushed Lime Day Bin 1	1310	1310		

EQUIPMENT LIST

EKPC Cooper 2 AQCS
B&McD Project No. 50198

Rev No.	Date	Prepared By	Checked By
A	10/20/2008	M FRIEDEL	
B	10/27/2008	M FRIEDEL	

Equipment Tag	Equipment Description	Furnish By	Install By	P&ID Name	Remarks
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2GSH-SLO-003	Hydrated Lime Silo	1310	1310		
2GSH-SLO-004	Hydrated Lime De-aeration Bin	1310	1310		
2WSW-PMP-002A	AQCS Lance Water Pump 1	1310	1310		
2WSW-PMP-002B	AQCS Lance Water Pump 2	1310	1310		
2WSW-TNK-001	AQCS Lance Water Tank	1310	1310		
2AAQ-BLR-001	Ammonia Dilution Air Blower 1	1330	1330		
2AAQ-BLR-002	Ammonia Dilution Air Blower 2	1330	1330		
2AAQ-PMP-001	Ammonia Forwarding Pump 1	1330	1330		
2AAQ-PMP-002	Ammonia Forwarding Pump 2	1330	1330		
2AAQ-PMP-003	Ammonia Condensate Return Pump 1	1330	1330		
2AAQ-PMP-004	Ammonia Condensate Return Pump 2	1330	1330		
2AAQ-SKD-001	Ammonia Unloading Skid	1330	1330		
2AAQ-SKD-002	Ammonia Vaporizing Skid	1330	1330		
2AAQ-SKD-003	Ammonia AFCU Skid	1330	1330		
2AAQ-TNK-001	Ammonia Storage Tank	1330	1330		
2AAQ-TNK-002	Ammonia Condensate Collection Tank	1330	1330		
2BAG-DPR-004A	SCR Inlet Damper	1330	1330		
2BAG-DPR-004B	SCR Outlet Damper	1330	1330		
2BAG-DPR-004C	SCR Bypass Damper	1330	1330		
2GSA-ABS-001	SCR	1330	1330		
2WSW-PMP-001A	AQCS Water Forwarding Pump 1	2190	8320		
2WSW-PMP-001B	AQCS Water Forwarding Pump 2	2190	8320		
2ACA-CPR-001	AQCS Air Compressor 1	2710	8320		
2ACA-CPR-002	AQCS Air Compressor 2	2710	8320		
2ACA-DRY-001	AQCS Control Air Dryer	2710	8320		
2ACA-TNK-001	AQCS Service Air Receiver	2710	8320		
2ACA-TNK-002	AQCS Control Air Receiver	2710	8320		
2EAP-TFM-010A	Unit Auxiliary Transformer A	5120	8410		
2EAP-TFM-010B	Unit Auxiliary Transformer B	5120	8410		
2EAP-GCB-001	Generator Circuit Breaker	5210	8410		
2CEM-SKD-001	Continuous Emissions Monitoring Skid	6310	8320		
0GSH-FDR-001	Lime Feeder	8320	8320		
0GSH-SLO-001	Lime Dust Silo	8320	8320		
2AHF-BLR-003	Fly Ash Exhauster 3	8320	8320		
2AHF-BLR-003	Fly Ash Silo 3 Bin Vent Filter Blower	8320	8320		
2AHF-BLR-003	Fly Ash Silo Fluidizing Air Blower 3	8320	8320		
2AHF-BLR-004	Fly Ash Exhauster 4	8320	8320		
2AHF-BLR-004	Fly Ash Silo 4 Bin Vent Filter Blower	8320	8320		
2AHF-BLR-004	Fly Ash Silo Fluidizing Air Blower 4	8320	8320		
2AHF-FAN-003	Fly Ash Dry Unloader 3 Vent Fan	8320	8320		
2AHF-FAN-004	Fly Ash Dry Unloader 4 Vent Fan	8320	8320		
2AHF-FLT-003	Fly Ash Silo 3 Bin Vent Filter	8320	8320		
2AHF-FLT-004	Fly Ash Silo 4 Bin Vent Filter	8320	8320		
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2AHF-ULD-003A	Fly Ash Wet Unloader 3	8320	8320		
2AHF-ULD-003B	Fly Ash Dry Unloader 3	8320	8320		
2AHF-ULD-004A	Fly Ash Wet Unloader 4	8320	8320		
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2BAG-DPR-001A	FD Fan A Isolation Damper	8320	8320		
2BAG-DPR-001B	FD Fan B Isolation Damper	8320	8320		
2BAG-DPR-002A	Primary Air Fan A Isolation Damper	8320	8320		
2BAG-DPR-002B	Primary Air Fan B Isolation Damper	8320	8320		
2BAG-FAN-001A	FD Fan A	8320	8320		
2BAG-FAN-001B	FD Fan B	8320	8320		
2BAG-FAN-002A	Primary Air Fan A	8320	8320		
2BAG-FAN-002B	Primary Air Fan B	8320	8320		
2BAG-HTX-001	Air Heater	8320	8320		

EQUIPMENT LIST

EKPC Cooper 2 AQCS
B&McD Project No. 50198

Rev No.	Date	Prepared By	Checked By
A	10/20/2008	M FRIEDEL	
B	10/27/2008	M FRIEDEL	

Equipment Tag	Equipment Description	Furnish By	Install By	P&ID Name	Remarks
2BAG-HTX-002	Secondary Air Steam Coil Air Heater	8320	8320		
2BAG-HTX-003	Primary Air Steam Coil Air Heater	8320	8320		
2BAG-SKD-001A	FD Fan A Lube Oil Skid	8320	8320		
2BAG-SKD-001B	FD Fan B Lube Oil Skid	8320	8320		
2BAG-SKD-002A	Primary Air Fan A Lube Oil Skid	8320	8320		
2BAG-SKD-002B	Primary Air Fan B Lube Oil Skid	8320	8320		
2BAG-VFD-001A	FD Fan A VFD	8320	8320		
2BAG-VFD-001B	FD Fan B VFD	8320	8320		
2GSH-SLO-001	Pebble Lime Silo	8320	8320		

3.0 CONTRACTING APPROACH

3.1 GENERAL APPROACH

The contracting approach used as a basis for this cost estimate was a multiple contract approach. As shown in Table 3.1, the contracts were broken up into two major categories; Furnish & Erect contracts and Equipment contracts. The Furnish and Erect contracts fall under two categories which include contracts to the major technology providers and general construction contracts. This approach provides the least risk for the Owner in meeting the Consent Decree performance requirements because there is single source responsibility for the emissions equipment. The Equipment contracts were setup in recognition of long lead time items that will need to be ordered early in the project to support the schedule and are not impacted by the selection of other contractors.

This Section contains detailed descriptions of each contract along with an itemized list of the scope being provided for each. To assist the reader in understanding the coordination of work between the multiple contracts, this Section also provides detailed information on the coordination of responsibilities for design, fabrication, delivery, receipt & protection, foundations, piping, wiring, erection, commissioning and startup interfaces.

3.2 CONTRACT LIST

The following is the list of contracts that were used as a basis for this cost estimate:

TABLE 3.1
List of Contracts

FURNISH & ERECT CONTRACTS	
C1310	CFB Dry FGD System
C1330	Selective Catalytic Reduction
C1350	Boiler Modifications
C8110	Site Preparation and Foundations
C8320	Mechanical Construction
C8410	Electrical Construction
EQUIPMENT CONTRACTS	
C5120	Large Power Transformers
C5310	Medium and Low Voltage Switchgear
C5330	Motor Control Centers
C5430	UPS
C5210	Generator Circuit Breakers
C5220	Isophase Bus Modifications
C6110	Distributed Control System Modifications
C2190	Water Pumps
C2710	Compressed Air System
C6310	Continuous Emission Monitoring System

3.3 INTERFACE SCHEDULE

The following table identifies the interfaces between contracts to identify the responsibilities of each contract to assure equipment foundations, receipt, installation, piping and wiring are properly accounted for on each contract.

TABLE 3.2
Contracts Interfaces

CONTRACT		CONTRACT INTERFACES				
NO.	**DESCRIPTION**	**RCVD BY**	**INST BY**	**FDNS BY**	**PIPE BY**	**WIRE BY**
FURNISH & ERECT CONTRACTS						
C1310	CFB Dry FGD System	C1310	C1310	C8110	C1310/C8320	C8410
C1330	Selective Catalytic Reduction	C1330	C1330	C8110	C8320	C8410
C1350	Boiler Modifications	C1350	C1350	NA	C1350	C1350
C8110	Site Preparation and Foundations	C8110	C8110	C8110	NA	NA
C8320	Mechanical Construction	C8320	C8320	C8110	C8320	C8410
C8410	Electrical Construction	C8410	C8410	C8110	NA	C8410
EQUIPMENT CONTRACTS						
C5120	Large Power Transformers	C8410	C8410	C8110	C8110	C8410
C5310	Medium and Low Voltage Switchgear	C8410	C8410	C8110	NA	C8410
C5330	Motor Control Centers	C8410	C8410	C8110	NA	C8410
C5430	UPS	C8410	C8410	C8110	NA	C8410
C5210	Generator Circuit Breakers	C8410	C8410	C8110	NA	C8410
C5220	Isophase Bus Duct Modifications	C8410	C8410	C8110	NA	C8410
C6110	Distributed Control System Modifications	C8410	C8410	NA	NA	C8410
C2190	Water Pumps	C8320	C8320	C8110	C8320	C8410
C2710	Compressed Air System	C8320	C8320	C8110	C8320	C8410
C6310	Continuous Emission Monitoring System	C8410	C8410	C8110	C8320	C8410

3.4 CONTRACT SCOPES

3.4.1 General

The following scope descriptions itemize the general content of the contracts that are currently contemplated. The "Contract interfaces" identify responsibilities for foundations, receipt of equipment and materials, construction/erection, and special interfaces to assist the reader in understanding the coordination of work. Assumptions have been made in preparing the scope description listing of items.

The Engineer will prepare drawings and specifications for use as the technical portion of the work package documents for equipment and construction packages. Work packages are indicated as the deliverables and will be issued to the Constructor.

General guidelines used are as follows.

- **Underground Utilities**

The scope of the contracts is based on an engineering sequence to permit design and construction of underground utilities as early as possible in the construction sequence. This approach allows completion of trenching and excavation activities earlier to permit better access and coordination of contractors or construction crafts. Installation of storm water drains, underground piping, electrical utilities and grounding along with the relocation of existing utilities will be included in Contract C8110 – Site Preparation and Foundations.

- **Piping and Instrumentation**

Equipment, piping and instrumentation furnished by equipment contracts will be erected and installed by Contract C8320 – Mechanical Construction. Above and below (if needed) ground piping and instrumentation is generally included in Contract C8320 – Mechanical Construction.

- **Wiring**

Raceway and cabling furnished by equipment contracts will be erected and installed by Contract C8410 – Electrical Construction. Major electrical equipment installation, wiring, and all interconnecting wiring for systems and equipment are generally included in Contract C8410 – Electrical Construction. Wiring for lighting/convenience outlets, HVAC and communication system is also included in the Contract C8410 – Electrical Construction.

- **Instrument Calibration**

All instruments will be factory calibrated, unless otherwise noted. (i.e. pH Analyzers, etc.). Contract C8320 – Mechanical Construction, if required, will perform subsequent calibration. In general instruments will be provided with equipment contracts with the exception of balance of plant. Instruments for balance of plant will be identified and supplied under the Contract C8320 - Mechanical Construction.

- **Electrical Testing**

Contract C8410 – Electrical Construction will perform all electrical equipment and wire testing. Manufacturer's field services are furnished by EKPC (through equipment contracts) to provide technical direction for equipment testing. Personnel to perform wire checking and de-energized testing of wiring systems, equipment and controls. This Contract will provide support labor for EKPC's use.

- **Start-up**

Engineer will provide start-up coordination. EKPC provides operating personnel. Contractors provide the construction labor and superintendents required to place equipment and systems into operation. Manufacturer's field services are furnished by EKPC (through equipment contracts) to provide technical direction for equipment start-up.

3.4.2 Furnish and Erect Contracts

CONTRACT C1310 – CFB DRY FGD SYSTEM

A. General Description: Design, fabricate, deliver and erect one flue desulfurization system for Unit

2. The scope of this contract includes the following:

1. One circulating fluidized bed (CFB) scrubber including the following equipment:
    a. CFB reactor tower.
    b. Lime handling and hydration system
        (i) Pebble lime transport system from storage tank to hydration systems.
        (ii) Pebble lime hydration system including (2) 100% capacity pebble lime hydrators.
        (iii) Process water tank sized for one hour of storage.
        (iv) Water injection system including (3) 50% high pressure water pumps.
        (v) Hydrated lime day bin.
        (vi) Hydrated lime injection system including (2) 100% blowers.
        (vii) All necessary piping and valves for a complete functional system
2. Pulse Jet Fabric Filter (PJFF) for removal of fly ash and CFB reaction products.
    a. Fabric filter compartments, inlet and outlet plenums, filter bags and cages and internal bypass system.
    b. Air compressors for pulse jet air supply

   c. PJFF product removal system including (2) air slides with dosage valves for product recycle and (2) air slide blowers, (1) CFB reactor bottom removal system including surge bins and transport system to the waste product silo.
   d. All necessary piping and valves for a complete functional system
3. Two new ID fans including the following:
   a. Two (2) 50% capacity centrifugal fans.
   b. Single speed electric motor drive for each fan suitable for outdoor installation.
   c. Variable Frequency Drives (VFD) for each ID fan.
   d. Single louver isolation dampers for each fan.
   e. Air cooled lubrication system for fan and motor bearings.
   f. Vibration monitoring system.
4. The following ductwork and flue gas system components:
   a. CFB reactor duct from air heater outlet duct interface supplied by Contract C1330 to CFB inlet.
   b. CFB reactor outlet to PJFF inlet.
   c. PJFF outlet to ID Fan inlet.
   d. ID Fan outlet to chimney inlet duct interface supplied by Contact C1330.
   e. CFB flue gas recirculation duct and damper.
   f. Ductwork test ports, and miscellaneous other ports including ports for installation of SO_2 monitors upstream and downstream of the reactor to be installed by others.
   g. Expansion joints for ducts supplied by this contract.
5. Access platforms, ladders, stairs and handrail to provide maintenance access to all equipment provided by this contract including:
   a. Reactor access platforms with provisions for interfaces with elevator provided by others (Contract C8320 – Mechanical Construction).
   b. Ductwork test ports and monitoring equipment.
   c. Ductwork dampers and seal air systems.
6. Structural and miscellaneous steel for supporting all equipment supplied by this contract.
7. Monorails, jib cranes, hoists and trolleys required for equipment maintenance.
8. All field mounted instrumentation required to monitor and operate the equipment provided by this contract.
9. PLC based control system to control all equipment supplied under this contract.
10. Model study (gas flow) from the ductwork interface with the ID fan inlet duct through the SCR reactor and fabric filter including all ductwork in the scope of this contract.

11. Provide surface preparation, prime and finish coatings for all structures, equipment, piping and systems provided by this contract.
12. Furnish services for technical direction start-up and to assist EKPC in placing equipment into operation.
13. Performance testing of system.

B. Contract Interfaces:
   1. Contract C8320 – Mechanical Construction: Provides pebble lime storage silo, waste product transport system and waste product silos. Installs air compressors for instrument air supply and water pumps for makeup water supply for this contract.
   2. Contract C8110 – Site Preparation and Foundations: Provides foundations for all FGD equipment.
   3. Contract C8410 – Electrical Construction: Performs wiring for all equipment and installation of VFD's.
   4. Contract C6110 – Distributed Control System Modifications: Provides the DCS interface cabinets and performs the programming and configuration of the FGD system controls into the existing plant DCS system.
   5. Contract C2710 – Compressed Air System: Provides instrument air compressors to operate equipment supplied under this contract with exception to the fabric filter pulsing air.

<u>CONTRACT C1330 – SELECTIVE CATALYTIC REDUCTION SYSTEM</u>

A. General Description: Design, fabricate, deliver and erect one SCR system. The scope of this contract includes the following:
   1. SCR reactor housing.
   2. SCR catalyst.
   3. Ammonia injection grid.
   4. Hoists and monorails required for SCR maintenance.
   5. Aqueous ammonia storage and vaporization system including the following:
      a. Aqueous ammonia unloading station and 10 day storage tank.
      b. Two (2) 100% aqueous ammonia forwarding pumps.
      c. One (1) ammonia vaporization skid with two (2) 100% ammonia vaporizers.
      d. One (1) dilution air skid with two (2) 100% blowers.
   6. One (1) ammonia flow control unit (AFCU).
   7. The following ductwork and flue gas system components:
      a. Economizer outlet to SCR inlet.

b. SCR outlet to airheater inlet.
c. SCR bypass ductwork.
d. Airheater outlet to CFB inlet duct interface supplied by contract C1310.
e. ID Fan outlet to chimney inlet duct interface supplied by contact C1310.
f. Ductwork from new FD fans to new airheater and back to FD fan discharge duct interface at boiler.
g. Ductwork from new PA fans to new airheater and back to PA fan discharge duct interface at boiler.
h. Tempering ductwork from PA fan discharge back to interface at boiler.
i. Flue gas flow dampers and distribution devices required for operation of the system.
j. Ductwork test ports, and miscellaneous other ports.
k. Expansion joints for ducts supplied by this contract.

8. All necessary safety equipment including eye-wash stations and ammonia leak detectors.
9. All necessary piping and valves for a complete functional system
10. PLC control system to control all equipment supplied under this contract.
11. All instrumentation required to monitor and operate the equipment supplied under this contract.
12. Model study (gas flow) from the ductwork interface with the existing economizer outlet duct through the SCR system and back to the airheater inlet.
13. Provide surface preparation, prime and finish coatings for all structures, equipment, piping and systems provided by this contract.
14. Furnish services for technical direction for start-up and to assist EKPC in placing equipment into operation.
15. Performance testing of the system.

B. Contract Interfaces:
1. Contract C8110 – Site Preparation and Foundations: Provides foundations.
2. Contract C8320 – Mechanical Construction: Installs air compressors for instrument air supply for this contract.
3. Contract C8410 – Electrical Construction: Performs wiring for all equipment supplied under this contract.
4. Contract C6110 – Distributed Control System Modifications: Provides the DCS interface cabinets and performs the programming and configuration of the FGD system controls into the existing plant DCS system.

5. Contract C2710 – Compressed Air System: Provides instrument air compressors to operate equipment supplied under this contract.

CONTRACT C1350 – BOILER MODIFICATIONS

A. General Description: Design, fabricate, deliver and erect boiler upgrades including the following scope:
   1. Boiler low NOx burners and over-fire air (OFA) installation including the following:
      a. Eighteen (18) low NOx burners
      b. Eighteen (18) new tile throat assemblies
      c. Eight (8) OFA ports with registers and furnace bent tube openings
      d. New OFA plenum and ducts to supply the OFA ports located on the furnace rear wall.
   2. Addition of 18 rows of primary superheater surface and header.
   3. Replacement of 3 rows of the reheater outlet bank.
   4. Removal of economizer bank from existing economizer.
   5. New economizer bank and piping located in ductwork downstream of SCR including new steam sootblower system.

B. Contract Interfaces: None

CONTRACT C8110 – SITE PREPARATION AND FOUNDATIONS

A. General Description: This is a furnish and construct contract for site preparation and the installation of foundations. It includes clearing, grubbing, grading, installation or modification of roadways along with the construction of temporary facilities to support mobilization of other construction contractors to the project site. It also includes installation of underground utilities - ductbank, grounding, piping for the project along with relocating existing utilities as necessary. Scope include the following:
   1. Perform clearing, grubbing, and grading of required area on plant site.
   2. Performing sampling, testing and analysis of the site soil compaction.
   3. Performing rough and finish grading for the following:
      a. New environmental equipment areas.
      b. Construction parking including surfacing.
      c. Construction lay-down including surfacing.
   4. Construction service roads.
   5. Underground utilities relocation if required.

6. Underground piping installation including embedded piping, under slab piping, and cathodic protection for underground piping as required.
7. Construction power center including incoming electrical service.
8. Construction water facility.
9. Temporary yard lighting.
10. Fencing and gates.
11. Permanent plant roads including subgrade preparation, grading, drainage structures, crushed rock, paving, seeding and erosion protection.
12. Storm drainage system.
13. Perform final trash and construction debris removal and disposal of required areas on plant site.
14. Restore temporary construction facilities (runoff ponds, lay-down area, temporary fencing, temporary utilities, etc.).
15. Perform remediation and soil replacement in areas containing contaminated materials.
16. Demolition of existing structures in all areas of new construction.
17. Install and construct mats, foundations, grade beams and anchor bolts as required for:
    a. Equipment supplied under Contract C1310 – CFB Dry FGD System.
    b. Equipment supplied under Contract C1330 – Selective Catalytic Reduction.
    c. Equipment supplied under Contract C8320 – Mechanical Construction.
    d. Equipment supplied under Contract C8410 – Electrical Construction.
    e. CEM enclosure foundation under Contract C6310 – Continuous Emissions Monitoring Systems.
    f. Miscellaneous foundations for the mechanical and electrical equipment (Contracts C5120, C5310, C5330, C5210, C2190, C2710).
    g. Miscellaneous foundations.
18. Furnish and install below grade electrical grounding grid.
19. Excavation, subgrade preparation, dewatering and backfill for all foundations.
20. Perform soil compaction and concrete testing during construction.
21. Furnish and install electrical manholes, duct banks, and all below grade conduit embedded in or under concrete.
22. Furnish and install permanent drains to existing system as required.
23. Design, manufacture, test and deliver to site the following Equipment and Materials including:
    a. Concrete and rebar.

   b. Asphalt.
   c. Seeding.
24. Construction labor, supervision, materials, tools, equipment, machinery, scaffolding and blocking necessary for performing final construction work not included in other contracts including the following:
   a. Finish grading.
   b. Storm drainage system including curbs and gutters, if applicable.
   c. Paving (asphalt and concrete).
   d. Rocking surfaces.
   e. Seeding, sodding and landscaping.
   f. Sidewalk constructing.
   g. Road and parking lot marking.
25. Final dressing of waste and borrow areas.

CONTRACT C8320 – MECHANICAL CONSTRUCTION

A. General Description: Furnish and install equipment and piping of a general nature not furnished with other packages including:
   1. Hangers and pipe supports.
   2. In-line special items.
   3. Small trim valves.
   4. Painting and labeling systems.
   5. Miscellaneous steel for pipe hangers and pipe supports.
   6. Pipe rack between fly ash silo's and CFB scrubber area.
   7. Furnish and erect field erected tanks:
      a. Waste product silos.
      b. Pebble lime silo.
   8. Furnish and install the following lime unloading equipment:
      a. Lime feed system to prevent arsenic poisoning of SCR system including the following:
         i. 150 ton lime shop fabricated silo.
         ii. Screw feeder to spread lime on coal conveyor.
      b. Pebble lime truck unloading station.
   9. Furnish and install two new FD and two new PA fans including the following:
      a. Two (2) 50% capacity centrifugal FD fans.
      b. Two (2) 50% capacity centrifugal PA fans.

   c. VFD for each FD fan.
   d. IVC dampers for each PA fan.
   e. Single louver isolation dampers for each FD and PA fan.
   f. Vibration monitoring system for FD fans.
   g. Steam coil airheaters at the discharge of the FD and PA fans.
10. One new tri-sector air preheater to replace existing primary and secondary airheaters.
11. Install centrifugal water pumps and motors including, but not limited to, the following pumps:
    a. Makeup water forwarding pumps.
12. Furnish and install makeup water forwarding pump screen filters.
13. Furnish and install the following buildings including HVAC equipment:
    a. Waste product handling blower building.
14. Furnish and install traction type elevator including all related structural steel, paneling, girts, etc for the CFB reactor.
15. Furnish and install ductwork insulation and lagging.
16. Furnish and install all control valves.
17. Unload, receive, store (if required), and install the following equipment furnished by other packages:
    a. Water pumps furnished by Contract C2190 – Water Pumps.
    b. Air compressor furnished by Contract C2710 – Compressed Air System.
18. Furnish and install line mounted instruments for monitoring and analog control of the following supporting systems and associated equipment.
19. Furnish and install miscellaneous instruments and transmitters not included in another equipment package, including installation materials, such as brackets, adapters, tubing, etc.
20. Perform final calibration of instruments.
21. Fire protection equipment and materials including:
    a. Piping and valves to extend the existing underground fire protection water loop.
    b. Dry pipe fire sprinkler systems for the following areas:
       (i) Transformers.
       (ii) CFB reactor.
    c. Fire detection systems for the above areas.
    d. Fire alarm system including:
    e. Main Fire Panel.
    f. Local Fire Panels.

22. Complete checkout, testing and assisting EKPC in placing into service of all mechanical systems and equipment installed under this package including, but not limited to, the following:
    a. Hydro tests.
    b. Lube oil system flushing.
23. Design, furnish and install the plant heat tracing system for all areas (if required). Work shall be completed to specified terminal points and include monitoring system. Wiring from terminal points will be by Contract C8410 – Electrical Construction.
24. Provide finish painting services and materials including:
    a. Surface preparation abrasives and paint.
    b. Performing surface preparation.
    c. Performing touch-up painting for equipment and materials provided by Contract C1310 – CFB Dry FGD System and C1330 – Selective Catalytic Reduction.
    d. Applying final paint systems to equipment and materials installed by Contract C8320 including the following:
        (i) Equipment.
        (ii) Shop fabricated and field erected tanks
        (iii) Unlagged carbon steel ductwork and vessels.
        (iv) Pipe rack to shared facilities area.
25. Providing final cleanup of all areas worked around or painted by this Contract.

B. Contract Interfaces:
1. Contract C1310 – CFB Dry FGD System.
    a. Performs touch-up painting and insulating for equipment provided under Contract C1310.
2. Contract C1330 – Selective Catalytic Reduction.
    a. Performs touch-up painting and insulating for equipment provided under Contract C1330.
3. Contract C2710 – Compressed Air System.
    a. Furnishes compressors installed by this contract.
4. Contract C8110 – Site Preparation and Foundations.
    a. Furnishes and installs foundations for equipment under this contract.
5. Contract C8410 – Electrical Construction.
    a. Contract C8410 installs wiring for all equipment provided under this contract.

CONTRACT C8410 – ELECTRICAL CONSTRUCTION

A. General Description: Furnish and install all electrical equipment and systems as described below:

1. Furnish and install power control module enclosure (PCM).
2. Install and perform wiring of all major electrical equipment. Receive, unload, store, install and wire the following equipment:
   a. Contract C5120 – Large Power Transformers.
   b. Contract C5310 – Medium and Low Voltage Switchgear
   c. Contract C5330 – Motor Control Centers.
   d. Contract C5430 – UPS.
   e. Contract C5210 – Generator Circuit Breakers.
   f. Contract C5220 – Isolated Phase Bus Duct Modifications.
   g. Contract C6110 – Distributed Control System Modifications.
   h. Contract C1310 – CFB Dry FGD System –VFD's.
   i. Contract C8320 – Mechanical Construction - Heat trace monitoring panels.
   j. Contract C6310 – Continuous Emissions Monitoring Systems.
3. Provide, install and perform wiring of the following electrical equipment:
   a. Lightning transformers.
   b. 480V power panels.
   c. 120/208V power panels.
   d. Lighting contactors.
4. Perform wiring of all instrumentation, controls and electrical equipment and systems as required.
5. Furnish and install above grade conduit raceway systems.
6. Furnish and install cable tray.
7. Furnish and install wire and cable systems.
8. Perform electrical testing.
9. Make final grounding connections.
10. Furnish and install welding outlets.
11. Label cable tray and cable.
12. Perform structure-related wiring including:
    a. Furnish, install and wire lighting/convenience outlets.
    b. Wire HVAC systems.
    c. Furnish and install telephone based communication/paging system.
13. Provide electrical testing services including:
    a. Test equipment.

b. Personnel to perform wire checking and testing of wiring systems, equipment and controls.

14. Performing electrical system testing of the following systems:
    a. Large power transformers.
    b. Small power transformers.
    c. Switchgear.
    d. Bus duct.
    e. Motor control centers.
    f. Inverter system.
    g. Power panels and associated dry type transformers.
    h. Heat trace monitoring panels.
    i. Power wiring.
    j. Control wiring.
    k. Control systems.

3.4.3 Equipment Contracts

CONTRACT C5120 – LARGE POWER TRANSFORMERS

A. General Description:
   1. Manufacture, deliver, install and test two auxiliary power transformers.
B. Equipment and Materials:
   1. Two, three-winding, oil filled 20-4.16/4.16 kV Auxiliary Transformers rated 21/28MVA.
C. Construction: None.
D. Services: Manufacturer's field services for receiving, installation, testing and placing equipment into operation.
E. Contract Interfaces:
   1. Contract C8110 – Site Preparation and Foundations:
      a. Furnishes and installs foundations for equipment furnished by this contract.
   2. Contract C8410 – Electrical Construction:
      a. Furnish and install interconnecting field wiring between the switchgear and transformers, field devices and equipment.
      b. Conducts functional tests of relaying and control interfaces with balance of plant systems.
      c. Start-up and place into initial operation.
      d. Connects ground grid to transformers.
   3. Contract C5210 – Generator Breaker

4. Contract C5220 – Iso-phase Bus Duct Modifications

CONTRACT C5310 – MEDIUM AND LOW VOLTAGE SWITCHGEAR

A. General Description:
   1. Design, furnish, and deliver 5 kV switchgear, 480 volt switchgear, and 4160/480 volt transformers.
B. Equipment and Materials:
   1. 4160V switchgear
   2. 4160V – 480V transformers.
   3. 480V Switchgear
   4. Protective relays
C. Construction: None.
D. Services: Manufacturer's field services for technical direction of receiving, installation, testing and placing equipment into operation.
E. Contract Interfaces:
   1. Contract C8110 – Site Preparation and Foundations:
      a. Furnishes and installs foundations for equipment furnished by this contract.
   2. Contract C8410 – Electrical Construction:
      a. Receives, unloads, inventories, stores, installs and places into service equipment, materials and accessories furnished by this equipment package.
      b. Furnish and install interconnecting field wiring between the switchgear and transformers, field devices and equipment.
      c. Conducts functional tests of relaying and control interfaces with balance of plant systems.
      d. Start-up and place into initial operation.
      e. Connects ground grid to switchgear and transformers.

CONTRACT C5330 – MOTOR CONTROL CENTERS

A. General Description:
   1. Design, furnish, and deliver 480V MCC's.
B. Equipment and Materials:
   1. 480V Motor Control Centers.
C. Construction: None.
D. Services: Manufacturer's field services for technical direction of receiving, installation, testing and placing equipment into operation.

E. Contract Interfaces:
  1. Contract C8110 – Site Preparation and Foundations:
     a. Furnishes and installs foundations for equipment furnished by this contract.
  2. Contract C8410 – Electrical Construction:
     a. Receives, unloads, inventories, stores, installs and places into service equipment, materials and accessories furnished by this equipment package.
     b. Furnish and install interconnecting field wiring between the MCC's and field devices and equipment.
     c. Conducts functional tests of relaying and control interfaces with balance of plant systems.
     d. Start-up and place into initial operation.
     e. Connects ground grid to MCC's.

<u>CONTRACT C5430 – UPS</u>

A. General Description:
  1. Design, furnish, and deliver one uninterruptible power supply (UPS).

B. Equipment and Materials: Includes one complete UPS system with the following equipment:
  1. Batteries
  2. Battery Chargers
  3. Inverter
  4. Static Switch
  5. Manual Bypass Switch
  6. DC Switchboard
  7. DC Panelboard
  8. AC Panelboard
  9. Alternate Source Transformer

C. Construction: None

D. Services: Manufacturer's field services for technical direction of receiving, installation, testing and placing equipment into operation.

E. Contract Interfaces:
  1. Contract C8410 – Electrical Construction

<u>CONTRACT C5210 – GENERATOR CIRCUIT BREAKERS</u>

A. General Description:
  1. Design, furnish, and deliver one generator breaker for the Unit 2 steam turbine generator.

B. Equipment and Materials:
   1. One (1) generator breaker
   2. Support steel
C. Construction: None.
D. Services: Manufacturer's field services for technical direction of receiving, installation, testing and placing equipment into operation.
E. Contract Interfaces:
   1. Contract C8110 – Site Preparation and Foundations:
      a. Furnishes and installs foundations for equipment furnished by this contract.
   2. Contract C8410 – Electrical Construction:
      a. Receives, unloads, inventories, stores, installs and places into service equipment, materials and accessories furnished by this equipment package.
      b. Furnish and install interconnecting field wiring between the generator circuit breaker and protective relay panels and equipment.
      c. Conducts functional tests of relaying and control interfaces with balance of plant systems.
      d. Start-up and place into initial operation.
      e. Connects ground grid to generator circuit breaker and support steel.

CONTRACT C5220 – ISOLATED PHASE BUS DUCT MODIFICATIONS

A. General Description:
   1. Design, furnish, and deliver isolated phase bus and connection hardware for routing from the new generator breaker to the new auxiliary transformers and the existing GSU.
B. Equipment and Materials:
   1. Isolated phase bus
   2. Support steel
   3. Connection Hardware for GSU, generator breaker, and auxiliary transformer.
C. Construction:
   1. Receive new sections of iso-phase bus duct. Modify existing bus duct as necessary to allow for the new generator circuit breaker. Provide new bus duct tap to new auxiliary transformers. Make connections between the generator circuit breaker and the existing/new iso-phase bus duct. Test new iso-phase bus duct and make ready for energization.
D. Contract Interfaces:
   1. Contract C5210 – Generator Breaker
   2. Contract C8410 – Electrical Construction

3. Contract C5120 – Large Power Transformers

CONTRACT C6110 – DISTRIBUTED CONTROL SYSTEM MODIFICATIONS (DCS)

A. General Description:
   1. The existing DCS will be expanded and modified to support the additions and modifications for the ID Fans by adding remote IO that is controlled by the boiler controller. Additional DCS controllers and IO will be installed to monitor and control Pebble Lime Preparation, Fly Ash removal, CFB Scrubber, Fabric Filter, Ammonia systems, and Balance of Plant scrubber systems. Individual systems requiring exclusive PLC or local control systems, such as fabric filter control, ammonia system, air compressor, and CEMS will be supplied with the equipment and interfaced to the DCS for monitoring and supervisory control through soft communications and limited hard wire connections..
B. Furnish field services for technical direction of erection, start-up and to assist EKPC in placing equipment into operation.
C. Contract Interfaces:
   1. Contract C8410 – Electrical Construction: Installs DCS cabinets and performs wiring for interfaces between FGD control system and plant control systems.

CONTRACT C2190 – WATER PUMPS

A. Provide the following water pumps for the Unit 2 scrubber systems.
   1. Two (2) 100% Make up water forwarding pumps.
B. Furnish services for technical direction of erection, start-up and to assist EKPC in placing equipment into operation.
C. Contract Interfaces:
   1. Contract C8110 – Site Preparation and Foundations.
   2. Contract C8320 – Mechanical Construction: Receives, unloads, stores and installs equipment.
   3. Contract C8410 – Electrical Construction: Performs wiring.

CONTRACT C2710 – COMPRESSED AIR SYSTEM

A. Equipment includes:
   1. Two oil-free rotary screw Compressed Air System with electric motors and soft start starters.
   2. Two air dryers, two dry air receivers and two wet air receivers if required.
B. Furnish services for technical direction of erection, start-up and to assist EKPC in placing equipment into operation.

C. Contract Interfaces:
   1. Contract C8110 – Site Preparation and Foundations.
   2. Contract C8320 – Mechanical Construction: Receives, unloads, stores and erects equipment. Provides air compressor building.
   3. Contract C8410 – Electrical Construction: Performs wiring.

CONTRACT C6310 – CONTINUOUS EMISSIONS MONITORING SYSTEMS

A. General Description:
   1. One complete continuous emissions monitoring (CEM) system and one complete Hg CEM system for Unit 2 scrubber outlet duct including climate controlled prefabricated CEM enclosures. CEMS shelter for enclosing all the equipment provided.
      a. CEMS Monitoring equipment shall include:
         i. SO_2.
         ii. NOx.
         iii. CO_2.
         iv. O_2
         v. Opacity.
         vi. Flow.
      b. Hg Monitoring equipment.
   2. Scrubber outlet duct probes and mounted equipment.
   3. Complete analysis, monitoring, recording, and reporting software.
   4. Dry extractive sampling system including probes, sample conditioning system, probe control system, and gas calibration system.
   5. Provide opacity monitors, SO_2, CO_2 monitors for installation in absorber inlet ductwork including climate controlled prefabricated CEM enclosures.
   6. Panel boards, transformers, automatic transfer switch, uninterruptible power supply (UPS) and HVAC.
   7. All hardware and software required to monitor and report SO_2, CO_2, and heat input, fuel consumption, and NOx.
   8. Data acquisition and handling system.

B. Furnish services for technical direction of erection, start-up and to assist EKPC in placing equipment into operation including:
   1. A complete factory calibration, checkout, and functional burn-in.
   2. Packaging and shipping of equipment and materials.

3. CEM certification testing in accordance with US EPA requirements.
4. Preparing O&M manuals.

C. Contract Interfaces:

1. Contract C8110 – Site Preparation and Foundations: Provides CEMS enclosure foundations.
2. Contract C8320 – Mechanical Construction: Receives, unloads, hauls, stores, and installs the CEM shelters and probes. Installs tubing from shelter to field mounted instruments.
3. Contract C8410 – Electrical Construction: Installs wiring and makes terminations as required for field mounted instruments and the CEM shelters.

* * * * *

4.0 SCHEDULE

4.1 CRITICAL MILESTONES

EKPC plans to have the Cooper Environmental Project complete in 2012 with the new equipment in service and operational in May. Several key milestones will need to be accomplished to meet the overall schedule for the project. A list of suggested important milestones as indicated on the draft project schedule included with this report are listed in Table 4.1.

Table 4.1 – Suggested Project Key Milestone Dates

Milestone	Milestone Date
Start Design Engineering	November 2008
Issue Contract C1310 - FGD System Bid Package	February 2009
Award Contract C1310 – FGD System	August 2009
Issue Contract C1330 - SCR Bid Package	March 2009
Award Contract C1330 – SCR	August 2009
Start Construction	April 2010
Mechanical Construction Substantial Completion	February 2012
Electrical Construction Substantial Completion	March 2012
FGD System Substantial Completion	May 2012
SCR Substantial Completion	May 2012

The schedule is of course dependent on project approvals and a variety of other influences. Table 4.1 indicates design engineering beginning immediately to prepare the remaining major bid specifications and preliminary designs to achieve the indicated schedule milestone dates.

4.2 PROJECT SCHEDULE

A level 2 project schedule was prepared by Burns & McDonnell for this Project which is included at the end of this section. The project schedule was developed around the major milestone of meeting the Consent Decree date for the FGD system to be in service by June 2012. The Consent Decree allows for the SCR to be in service by December 2012, but it is EKPC's desire to have the SCR in service at the same time as the FGD system.

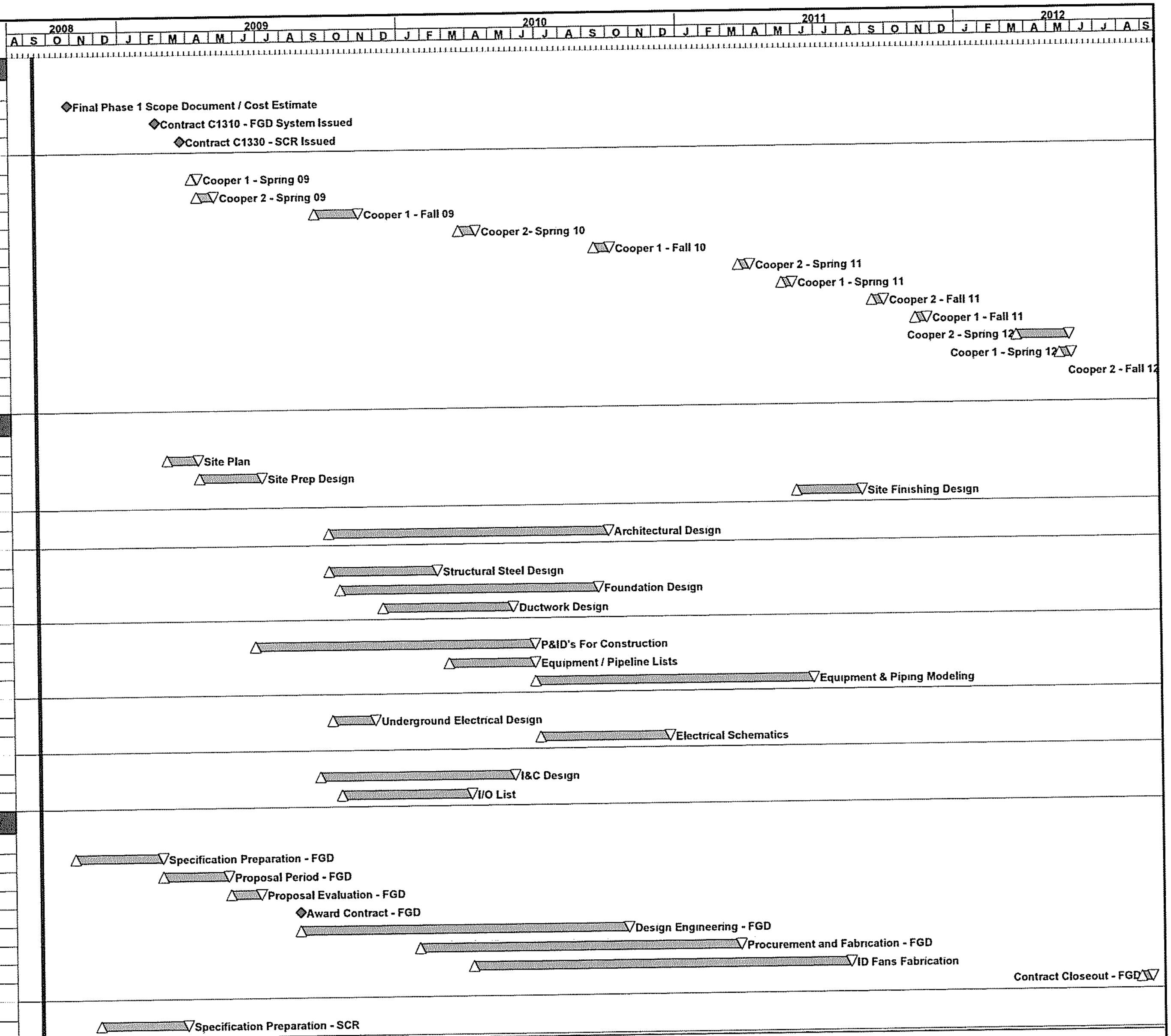
Several outages will be needed to make modification and perform construction that can only be accomplished with the unit off line. The existing primary air duct needs to be relocated to allow for the new ductwork to be installed. This work could be done early in the project as EKPC's outages will allow. There will also need to be major outage of approximately 10 weeks near the end of the construction period.

The schedule evaluation is based on an engineering start date of November 2008. This schedule is based on site preparation construction commencing in April 2010. The scope split for the equipment and construction contracts is described in Section 3.0 – Contracting Approach. The performance of each construction contract is anticipated to be continuous without intermediate demobilization and remobilization.

The schedules are based on early procurement of the long lead major plant equipment which consist of the fabric filters, FGD scrubbers, ID fans, fly ash handling equipment, transformers, DCS cabinets, electrical equipment, and other long lead equipment. Vendor submittals are required from each equipment contractor which will support the detailed design of infrastructure (foundations, piping, wiring, instrumentation, etc) required for installation of this equipment. Sufficient time has been built into the schedule for the Engineer to perform the detailed design to obtain competitive, lump sum bids for the respective construction.

* * * * *

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
General				
MILESTONES				
0001	Final Phase 1 Scope Document / Cost Estimate	0		27OCT08*
0002	Contract C1310 - FGD System Issued	0	19FEB09	
0012	Contract C1330 - SCR Issued	0	23MAR09	
Scheduled Outages				
0050	Cooper 1 - Spring 09	6	06APR09*	13APR09
0064	Cooper 2 - Spring 09	16	13APR09*	04MAY09
0052	Cooper 1 - Fall 09	41	14SEP09*	09NOV09
0066	Cooper 2- Spring 10	16	22MAR10*	12APR10
0054	Cooper 1 - Fall 10	16	13SEP10*	04OCT10
0068	Cooper 2 - Spring 11	11	21MAR11*	04APR11
0056	Cooper 1 - Spring 11	11	16MAY11*	30MAY11
0070	Cooper 2 - Fall 11	11	12SEP11*	26SEP11
0058	Cooper 1 - Fall 11	11	07NOV11*	21NOV11
0072	Cooper 2 - Spring 12	50	19MAR12*	25MAY12
0060	Cooper 1 - Spring 12	11	14MAY12*	28MAY12
0074	Cooper 2 - Fall 12	11	24SEP12*	08OCT12
0062	Cooper 1 - Fall 12	11	05NOV12*	19NOV12
Engineering				
Civil Engineering				
BME0100	Site Plan	30	02MAR09	10APR09
BME0105	Site Prep Design	60	13APR09	03JUL09
BME0110	Site Finishing Design	60	03JUN11	26AUG11
Architectural Engineering				
BME0135	Architectural Design	260	28SEP09	28SEP10
Structural Engineering				
BME0145	Structural Steel Design	100	28SEP09	16FEB10
BME0140	Foundation Design	240	12OCT09	14SEP10
BME0150	Ductwork Design	120	07DEC09	25MAY10
Mechanical Engineering				
BME0115	P&ID's For Construction	260	22JUN09	22JUN10
BME0120	Equipment / Pipeline Lists	80	03MAR10	22JUN10
BME0170	Equipment & Piping Modeling	260	23JUN10	21JUN11
Electrical Engineering				
BME0160	Underground Electrical Design	40	01OCT09*	25NOV09
BME0130	Electrical Schematics	120	30JUN10	14DEC10
I&C Engineering				
BME0155	I&C Design	180	14SEP09	25MAY10
BME0125	I/O List	120	12OCT09	30MAR10
Procurement				
Contract C1310 - CFB Dry FGD System				
BMP1310-05	Specification Preparation - FGD	80	28OCT08	18FEB09
BMP1310-10	Proposal Period - FGD	62	19FEB09	15MAY09
BMP1310-15	Proposal Evaluation - FGD	30	18MAY09	26JUN09
BMP1310-20	Award Contract - FGD	0	17AUG09	
BMP1310-25	Design Engineering - FGD	305	17AUG09	19OCT10
BMP1310-30	Procurement and Fabrication - FGD	300	20JAN10	15MAR11
BMP1310-40	ID Fans Fabrication	352	31MAR10	05AUG11
BMC1310-95	Contract Closeout - FGD	10	21AUG12	03SEP12
Contract C1330 - Selective Catalytic Reduction				
BMP1330-05	Specification Preparation - SCR	80	27NOV08	20MAR09



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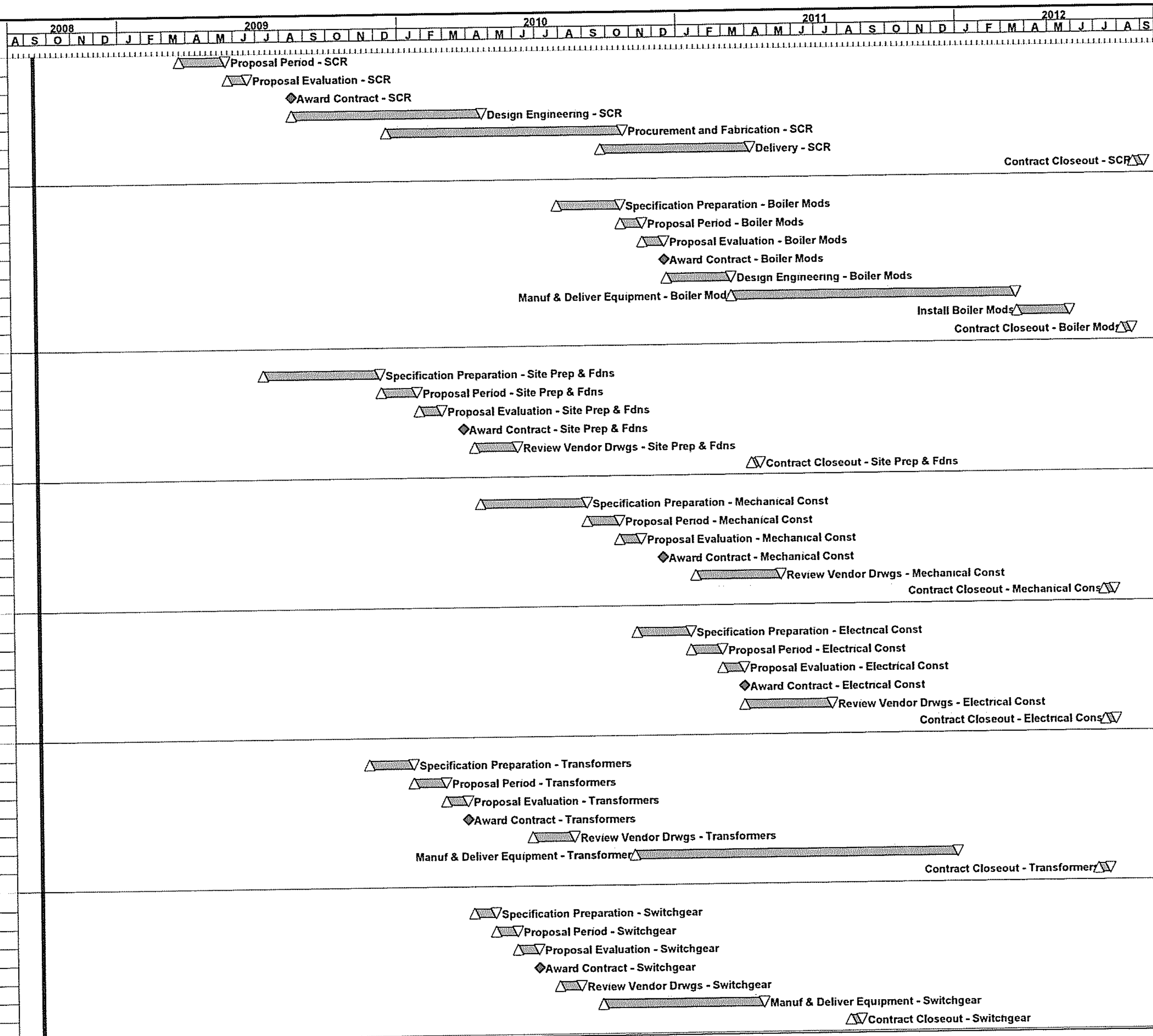
Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
BMP1330-10	Proposal Period - SCR	45	23MAR09	22MAY09
BMP1330-15	Proposal Evaluation - SCR	20	25MAY09	19JUN09
BMP1330-20	Award Contract - SCR	0	17AUG09	
BMP1330-25	Design Engineering - SCR	175	17AUG09	20APR10
BMP1330-30	Procurement and Fabrication - SCR	220	17DEC09	22OCT10
BMP1330-35	Delivery - SCR	140	23SEP10	06APR11
BMC1330-95	Contract Closeout - SCR	10	21AUG12	03SEP12
Contract C1350 - Boiler Modifications				
BMP1350-05	Specification Preparation - Boiler Mods	60	27JUL10	18OCT10
BMP1350-10	Proposal Period - Boiler Mods	20	19OCT10	15NOV10
BMP1350-15	Proposal Evaluation - Boiler Mods	20	16NOV10	13DEC10
BMP1350-20	Award Contract - Boiler Mods	0		13DEC10*
BMP1350-25	Design Engineering - Boiler Mods	60	17DEC10	10MAR11
BMP1350-35	Manuf & Deliver Equipment - Boiler Mods	265	11MAR11	16MAR12
BMC1350-40	Install Boiler Mods	50	19MAR12	25MAY12
BMP1350-95	Contract Closeout - Boiler Mods	10	02AUG12	15AUG12
Contract C8110 - Site Preparation & Foundations				
BMP8110-05	Specification Preparation - Site Prep & Fdns	110	06JUL09	04DEC09
BMP8110-10	Proposal Period - Site Prep & Fdns	33	07DEC09	22JAN10
BMP8110-15	Proposal Evaluation - Site Prep & Fdns	22	25JAN10	23FEB10
BMP8110-20	Award Contract - Site Prep & Fdns	0		23MAR10
BMP8110-30	Review Vendor Drwgs - Site Prep & Fdns	40	07APR10	01JUN10
BMC8110-95	Contract Closeout - Site Prep & Fdns	10	04APR11	15APR11
Contract C8320 - Mechanical Construction				
BMP8320-05	Specification Preparation - Mechanical Const	100	14APR10	31AUG10
BMP8320-10	Proposal Period - Mechanical Const	30	01SEP10	12OCT10
BMP8320-20	Proposal Evaluation - Mechanical Const	20	13OCT10	09NOV10
BMP8320-25	Award Contract - Mechanical Const	0		07DEC10
BMP8320-30	Review Vendor Drwgs - Mechanical Const	80	19JAN11	10MAY11
BMC8320-95	Contract Closeout - Mechanical Const	10	06JUL12	19JUL12
Contract C8410 - Electrical Construction				
BMP8410-05	Specification Preparation - Electrical Const	50	03NOV10	11JAN11
BMP8410-10	Proposal Period - Electrical Const	30	12JAN11	22FEB11
BMP8410-15	Proposal Evaluation - Electrical Const	20	23FEB11	22MAR11
BMP8410-20	Award Contract - Electrical Const	0		22MAR11
BMP8410-30	Review Vendor Drwgs - Electrical Const	80	23MAR11	13JUL11
BMC8410-95	Contract Closeout - Electrical Const	10	06JUL12	19JUL12
Contract C5120 - Large Power Transformers				
BMP5120-05	Specification Preparation - Transformers	40	16NOV09	12JAN10
BMP5120-10	Proposal Period - Transformers	30	13JAN10	23FEB10
BMP5120-15	Proposal Evaluation - Transformers	20	24FEB10	23MAR10
BMP5120-20	Award Contract - Transformers	0		23MAR10
BMP5120-25	Review Vendor Drwgs - Transformers	40	16JUN10	10AUG10
BMP5120-35	Manuf & Deliver Equipment - Transformers	300	29OCT10	23DEC11
BMP5120-95	Contract Closeout - Transformers	10	25JUN12	09JUL12
Contract C5310 - Med and Low Voltage Switchgear				
BMP5310-05	Specification Preparation - Switchgear	20	31MAR10	27APR10
BMP5310-10	Proposal Period - Switchgear	20	28APR10	25MAY10
BMP5310-15	Proposal Evaluation - Switchgear	20	26MAY10	22JUN10
BMP5310-20	Award Contract - Switchgear	0		22JUN10
BMP5310-25	Review Vendor Drwgs - Switchgear	20	21JUL10	17AUG10
BMP5310-35	Manuf & Deliver Equipment - Switchgear	150	15SEP10	12APR11
BMP5310-95	Contract Closeout - Switchgear	10	04AUG11	17AUG11



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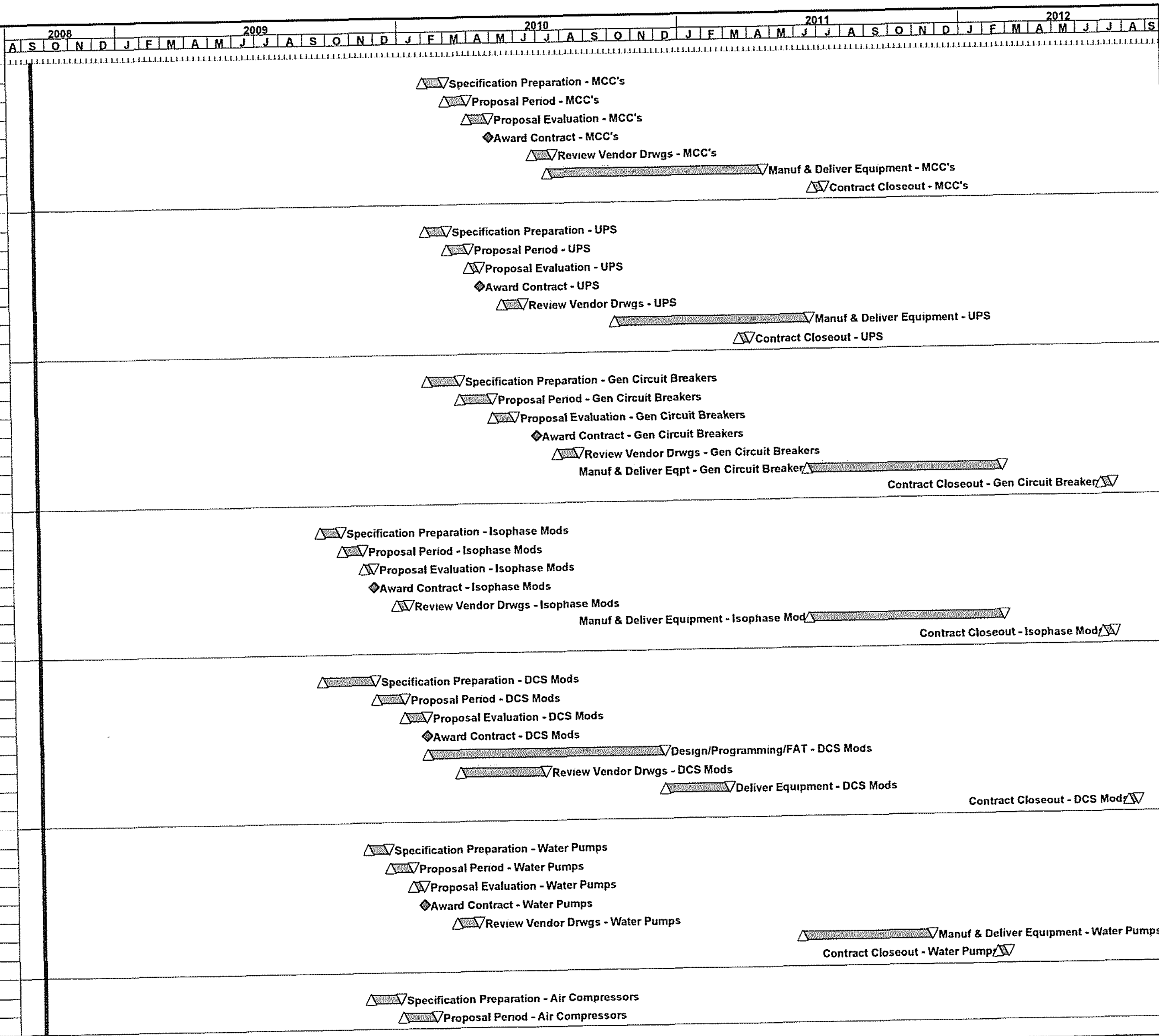
Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
Contract C5330 - Motor Control Centers				
BMP5330-05	Specification Preparation - MCC's	20	03FEB10	02MAR10
BMP5330-10	Proposal Period - MCC's	20	03MAR10	30MAR10
BMP5330-15	Proposal Evaluation - MCC's	20	31MAR10	27APR10
BMP5330-20	Award Contract - MCC's	0		27APR10
BMP5330-25	Review Vendor Drwgs - MCC's	20	23JUN10	20JUL10
BMP5330-35	Manuf & Deliver Equipment - MCC's	200	14JUL10	19APR11
BMP5330-95	Contract Closeout - MCC's	10	22JUN11	06JUL11
Contract C5430 - UPS				
BMP5430-05	Specification Preparation - UPS	20	03FEB10	02MAR10
BMP5430-10	Proposal Period - UPS	20	03MAR10	30MAR10
BMP5430-15	Proposal Evaluation - UPS	10	31MAR10	13APR10
BMP5430-20	Award Contract - UPS	0		13APR10
BMP5430-25	Review Vendor Drwgs - UPS	20	12MAY10	08JUN10
BMP5430-35	Manuf & Deliver Equipment - UPS	180	06OCT10	14JUN11
BMP5430-95	Contract Closeout - UPS	10	16MAR11	29MAR11
Contract C5210 - Generator Circuit Breakers				
BMP5210-05	Specification Preparation - Gen Circuit Breakers	30	03FEB10	16MAR10
BMP5210-10	Proposal Period - Gen Circuit Breakers	30	17MAR10	27APR10
BMP5210-15	Proposal Evaluation - Gen Circuit Breakers	20	28APR10	25MAY10
BMP5210-20	Award Contract - Gen Circuit Breakers	0		22JUN10
BMP5210-25	Review Vendor Drwgs - Gen Circuit Breakers	20	21JUL10	17AUG10
BMP5210-35	Manuf & Deliver Eqpt - Gen Circuit Breakers	180	10JUN11	17FEB12
BMP5210-95	Contract Closeout - Gen Circuit Breakers	10	25JUN12	09JUL12
Contract C5220 - Isophase Bus Modifications				
BMP5220-05	Specification Preparation - Isophase Mods	20	14SEP09*	09OCT09
BMP5220-10	Proposal Period - Isophase Mods	20	12OCT09	06NOV09
BMP5220-15	Proposal Evaluation - Isophase Mods	10	09NOV09	20NOV09
BMP5220-20	Award Contract - Isophase Mods	0		20NOV09
BMP5220-25	Review Vendor Drwgs - Isophase Mods	10	21DEC09	05JAN10
BMP5220-35	Manuf & Deliver Equipment - Isophase Mods	180	10JUN11	17FEB12
BMP5220-95	Contract Closeout - Isophase Mods	10	25JUN12	09JUL12
Contract C6110 - DCS Modifications				
BMP6110-05	Specification Preparation - DCS Mods	50	14SEP09	20NOV09
BMP6110-10	Proposal Period - DCS Mods	25	23NOV09	28DEC09
BMP6110-15	Proposal Evaluation - DCS Mods	20	29DEC09	26JAN10
BMP6110-20	Award Contract - DCS Mods	0		26JAN10
BMP6110-40	Design/Programming/FAT - DCS Mods	220	27JAN10	30NOV10
BMP6110-25	Review Vendor Drwgs - DCS Mods	80	10MAR10	29JUN10
BMP6110-35	Deliver Equipment - DCS Mods	60	01DEC10	22FEB11
BMP6110-95	Contract Closeout - DCS Mods	10	24JUL12	06AUG12
Contract C2190 - Water Pumps				
BMP2190-05	Specification Preparation - Water Pumps	20	09NOV09	04DEC09
BMP2190-10	Proposal Period - Water Pumps	20	07DEC09	05JAN10
BMP2190-15	Proposal Evaluation - Water Pumps	10	06JAN10	19JAN10
BMP2190-20	Award Contract - Water Pumps	0		19JAN10
BMP2190-25	Review Vendor Drwgs - Water Pumps	20	03MAR10	30MAR10
BMP2190-35	Manuf & Deliver Equipment - Water Pumps	120	25MAY11	09NOV11
BMP2190-95	Contract Closeout - Water Pumps	10	02FEB12	15FEB12
Contract C2710 - Compressed Air System				
BMP2710-05	Specification Preparation - Air Compressors	30	09NOV09	18DEC09
BMP2710-10	Proposal Period - Air Compressors	30	21DEC09	02FEB10



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BMP2710-15	Proposal Evaluation - Air Compressors	20	03FEB10	02MAR10
BMP2710-20	Award Contract - Air Compressors	0		02MAR10
BMP2710-25	Review Vendor Drwgs - Air Compressors	40	31MAR10	25MAY10
BMP2710-35	Manuf & Deliver Equipment - Air Compressors	170	21JUL10	15MAR11
BMP2710-95	Contract Closeout - Air Compressors	10	02FEB12	15FEB12
Contract C6310 - CEM System				
BMP6310-05	Specification Preparation - CEMS	25	21AUG09	24SEP09
BMP6310-10	Proposal Period - CEMS	20	25SEP09	22OCT09
BMP6310-15	Proposal Evaluation - CEMS	20	23OCT09	19NOV09
BMP6310-20	Award Contract - CEMS	0		19NOV09
BMP6310-25	Review Vendor Drwgs - CEMS	20	05JAN10	01FEB10
BMP6310-35	Manuf & Deliver Equipment - CEMS	130	01JUN11	30NOV11
BMP6310-40	Install CEMS	60	01DEC11	22FEB12
BMP6310-95	Contract Closeout - CEMS	10	25JUN12	09JUL12
Construction				
Contract C1310 - CFB Dry FGD System				
BMC1310-45	Structural Steel Installation - FGD	100	15SEP10	01FEB11
BMC1310-50	Reactor and Fabric Filter Installation	110	02FEB11	06JUL11
BMC1310-60	Piping and Instrument Installation - FGD	66	28JUN11	28SEP11
BMC1310-65	Ductwork & Duct Support Stl Installation - FGD	135	07JUL11	11JAN12
BMC1310-70	Install ID Fans	22	08AUG11	06SEP11
Contract C1330 - Selective Catalytic Reduction				
BMC1330-05	SCR Installation - SCR	360	23SEP10	09FEB12
BMC8410-15	Primary Air Duct Relocation	11	21MAR11	04APR11
Contract C8110 - Site Preparation & Foundations				
BMC8110-05	Civil / Underground Construction	110	07APR10	07SEP10
BMC8110-10	Foundation Construction	132	30JUN10	30DEC10
Contract C8320 - Mechanical Construction				
BMP8320-35	Mobilize - Mechanical Const	20	05JAN11	01FEB11
BMC8320-05	Install Eqpt - Mechanical Const	260	02FEB11	01FEB12
BMC8320-10	Install BOP Piping - Mechanical Const	260	16FEB11	15FEB12
BMC8320-15	Install Instrumentation - Mechanical Const	20	26JAN12	22FEB12
Contract C8410 - Electrical Construction				
BMC8410-10	Install BOP Electrical - Electrical Const	260	23MAR11	21MAR12
BMC1310-55	Electrical Installation - FGD	176	29MAR11	30NOV11
BMP6110-45	Install DCS	85	18MAY11	14SEP11
BMP5220-40	Install Isophase Mods	50	19MAR12	25MAY12
Startup				
MILESTONES				
0010	FGD System Startup and Commissioning	110	23DEC11	24MAY12
0015	SCR Startup and Commissioning	70	10FEB12	17MAY12
0030	Ductwork Tie-Ins	50	19MAR12	25MAY12
0020	FGD System In Operation	0		25MAY12
0025	CD Date - FGD System In Service	0		29JUN12*
Contract C1310 - CFB Dry FGD System				
BMC1310-90	Substantial Completion - FGD	1	25MAY12	25MAY12
Contract C1330 - Selective Catalytic Reduction				
BMC1330-90	Substantial Completion - SCR	0		17MAY12
Contract C8320 - Mechanical Construction				
BMS8320-05	Startup & Commissioning - Mechanical Const	120	24NOV11	09MAY12
BMC8320-90	Substantial Completion - Mechanical Const	0		15FEB12

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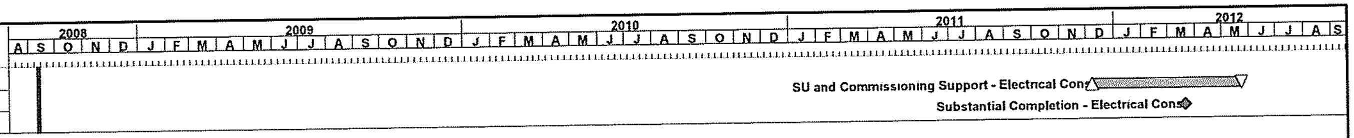
Contract C8410 - Electrical Construction				
BMS8410-05	SU and Commissioning Support - Electrical Const	120	08DEC11	23MAY12
BMC8410-90	Substantial Completion - Electrical Const	0		21MAR12



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5.0 COST ESTIMATE

5.1 GENERAL

An initial capital cost estimate for the proposed Cooper Unit 2 Environmental Project is included in Section 5.5 – Summary Cost Estimate. The estimated cost for these upgrades, inclusive of contingency, escalation, is approximately $324 million. No financing fees and interest during construction were included as directed by EKPC.

5.2 BASIS AND ASSUMPTIONS

The following describes the methodology used in the development of the Cooper Unit 2 SCR, fabric filter and dry scrubber addition cost estimate.

1. The estimate is based on the assumptions and scope of supply indicated in this section and Section 2.0 – Project Scope. A Layout Study, Preliminary Geotechnical Investigation, Induced Draft Fan Study, Auxiliary Power Study, Fly Ash Handling Study, Water Balance Study, Boiler Implosion Study, and Piping and Instrument Diagrams have not been developed for the Cooper Unit 2 Environmental Project. Design parameters and scope typically defined by these studies are estimated based on information provided by EKPC, preliminary calculations and Burns & McDonnell experience.
2. Major Engineered Equipment: Burns & McDonnell solicited and received budget level vendor quotations for the following major equipment:
    a. Boiler Modifications Required for Design Fuel and AQCS Equipment
    b. Selective Catalytic Reduction Reactor and Catalyst
    c. Aqueous Ammonia Storage and Supply System
    d. Fabric Filter
    e. Circulating Fluidized Bed FGD Scrubber
    f. Pebble Lime Storage Silo
    g. Lime Preparation, Storage and Feed System
    h. CFB Scrubber By-Product Recirculation and Removal System
    i. Induced Draft Fans and Motors
    j. ID Fan Variable Frequency Drives
    k. Scrubber Waste Product Handling System
    l. Waste Product Silos
    m. Forced Draft Fans and Motors
    n. Primary Air Fans and Motors
    o. Tri-Sector Air Heater

3. Balance of Plant Equipment: Burns & McDonnell utilized in-house information from similar projects.
4. Construction Estimates: Construction commodities and indirect costs were estimated using recent pricing and quantity take-offs from other similar projects in Burns & McDonnell's in-house database.
5. Labor rates: Labor rates and productivity factors were developed based on a project specific Area Labor Study prepared by Schumacher Consulting, LLC, included in Section 5.8 – Labor Study Report. The average non-escalated labor rate applied in the cost estimate is based on the Labor Study Attachment #2B Union All In Rate of $85.40 per hour ($2008).

Project Indirects: Estimates are based on Burns & McDonnell's experience as an Owner's Engineer and EPC contractor. Owner's costs were provided by EKPC.

5.2.1 Capital Cost Estimate Scope

A project scope description for the cost estimate is included at the end of this section. This description along with the drawings and lists included in Section 2.0 – Project Scope define the scope included in the cost estimate.

5.2.2 Major Capital Cost Estimate Assumptions

Several major assumptions were used in developing the capital cost estimate. These assumptions include the following:

- Commercial operation is assumed to be prior to May 29, 2012. The May 29 completion date allows a 30–day rolling average emissions rate to be established prior to the Consent Decree date of June 30, 2012.
- Labor is assumed union labor and available without excessive hourly incentives or incentive packages.
- A 20% mark-up (overhead and fee) is included on both materials and labor for subcontracted work.
- A productivity factor is applied to all site labor. This means more man-hours will be expended to complete the work than would be expended on a typical new facility on the Gulf Coast with ample, fully trained craft. These productivity factors were applied to account for the fact that adequate qualified labor with applicable experience may be limited in the area and for the general inefficiencies of retrofit work. Further, a relatively significant amount of work is planned on coal plants throughout the country for both new construction and for emissions controls retrofits. This is expected to create a shortage of qualified labor for such a project and result in utilization of labor that is not as efficient and requires more training. The current economic crisis in the United

States (potentially a global economic crisis) may postpone some of this work, but it is too early to predict any impact on future labor demand.

- Escalation is assumed to average 8% per year for materials and 5% per year for labor from now until the project is complete by June 2012.
- Contingency is included at 15% for estimate accuracy contingency and 10% for project definition contingency.
- Cost for Builder's Risk Insurance was not included.
- No sales tax was included.
- No financing fees or interest during construction was included.

5.2.3 Major Commercial Terms

The following lists the major commercial terms assumed in developing the cost estimates. Minor assumptions are either self evident in the data or have an insignificant effect on the estimated project capital costs.

- Project is assumed to be performed with multiple prime contracts for the construction work as defined in Section 3.0 – Contracting Approach. Major equipment identified in Section 3.0 and minor equipment items (piping specialties, small-bore piping, wiring and other construction commodities) are expected to be included in the construction contracts.
- Project will include multiple equipment procurement contracts including contracts for large power transformers, electrical equipment, DCS modifications, etc as defined in Section 3.0 – Contracting Approach.
- Project will be executed with durations similar to those shown on the project schedule with the objective of achieving the Project milestone dates. It is assumed that the project will be executed with a schedule sufficient to minimize overtime. A 50-hour workweek was assumed as a means of providing an incentive to attract labor. This includes 40 hours of straight time and 10 hours of overtime for all normal construction periods. A 70-hour workweek is assumed during outages. A 70-hour workweek was assumed during commissioning and start-up. No additional overtime is included to accommodate a compressed work schedule.
- A performance bond is included for all subcontract work at the rate of 1.5% of the estimated project contract costs (100% bond). A performance bond is not included for major equipment.
- Sales tax on construction consumables is not included. No other tax is included.
- The cost for a builder's risk policy for the project has not been included.

- Reasonable damage/bonus provisions related to schedule and performance will be negotiated between Owner and the contractors and equipment vendors. Anticipated levels for liquidated damages are as stated below (considered Industry Standard):
  - Total aggregate contract liquidated damages (LD) cap – maximum of 20-percent of contract price.
  - Project schedule - maximum of 15-percent of the contract price.

5.3 ECONOMIC CONDITIONS CONSIDERATIONS

An estimate for escalation of project costs has been included in the capital cost estimate. Escalation of construction labor, materials, and indirects was estimated based on historical data and Burns & McDonnell experience.

Escalation of construction labor was estimated to be approximately 5% annually throughout the project. This estimate of escalation is based upon the average increase in craft labor costs for the United States combined with known Union labor contract costs in the next two to three years.

The average annual escalation of skilled and common labor rates over the last four years throughout the United States has been approximately 4.0%. However, concurrent construction of base load coal fired power plants by multiple utilities during the 2008 to 2012 time period appears to be very probable given projected trends in coal and natural gas prices. Further, a significant quantity of air pollution control projects on existing facilities is likely. Such occurrences could have a significant effect on the availability of construction labor and the associated labor cost. Some consideration for such impacts has been included in the project costs. However, full impact of such conditions is unknown. In addition, the current economic crisis in the United States (potentially a global economic crisis) may postpone some of this work, but it is too early to predict any impact on future labor demand.

Escalation of equipment and materials was included in the project estimate at a rate of 8% per year. Equipment and materials represents the largest portion of the estimated cost. Since January 2004, steel pricing has experienced rapid escalation equating to a nearly a 100% increase in rebar and structural steel costs. Pipe and electrical commodities have also seen a high escalation during this time period. Due to this volatility, equipment suppliers have been providing pricing with short bid validity. This volatility has subsided slightly. However, steel pricing still remains elevated compared to those levels seen at this same time last year.

5.4 CONTINGENCY

A contingency of 15% of the overall project costs is included in the project cost. It is included to cover accuracy of pricing and commodity estimates for the defined project scope. This contingency is not intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) nor major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans).

On top of this, an additional project definition contingency should be added to cover general project scope additions required to meet the EKPC Consent Decree but not identified. Based upon the amount of preliminary design and project definition completed, Burns & McDonnell recommends a 10% contingency to cover such potential changes.

This overall level of contingency is felt adequate to cover normal deviations in pricing and normal deviations in the assumptions used to develop the project costs. However, it is likely not adequate to cover significant deviations from the project assumptions or major changes in market conditions. Deviations that may cause the project costs to exceed the estimated costs inclusive of contingency include excessive inflation (>8%), extreme shortage of qualified labor, extreme shortage of qualified construction contractors, change in contracting approach, and other similar changes. Such changes may be reflective of a moderate to high amount of new power plant or industrial plant construction or air pollution control retrofits.

5.5 SUMMARY COST ESTIMATE

The following capital cost estimate was developed for the Cooper Unit 2 Environmental Project.

PRELIMINARY COST ESTIMATE
EAST KENTUCKY POWER COOPERATIVE
COOPER STATION UNIT 2 AQCS
BMcD PROJECT 50198
SOMERSET, KENTUCKY
Rev A

SUMMARY SHEET		Equipment / Furnish & Erect Cost	Materials & Equipment Rental	Subcontract	Labor	Total
FGD & PJFF		$56,600,000				$56,600,000
ID FANS		$3,259,450			$532,896	$3,792,346
WASTE PRODUCT SYSTEM		$6,744,000	$20,948		$1,689,690	$8,454,639
DUCTWORK		$11,684,147			$9,239,728	$20,923,875
SCR		$12,000,000			$5,124,000	$17,124,000
AMMONIA SUPPLY		$2,934,000			$79,934	$3,013,934
FE TANKS		$1,294,560				$1,294,560
MISC PUMPS & EQUIPMENT		$420,315			$59,951	$480,266
WATER TREATMENT SYS		$109,804			$17,053	$126,857
ELECTRICAL EQUIPMENT		$6,985,000			$727,181	$7,712,181
TRANSFORMERS		$1,640,000			$432,978	$2,072,978
DCS MODIFICATIONS		$1,450,000				$1,450,000
CEMS		$1,261,000				$1,261,000
BOILER & AIR HEATER MOD		$11,661,320	$947,834		$7,244,781	$19,853,935
CIVIL			$1,152,659	$2,167,025	$586,546	$3,906,230
STEEL			$248,237	$8,446,627	$4,690,870	$13,385,734
CONCRETE			$3,878,448	$246,721	$5,576,605	$9,701,774
ARCHITECTURAL			$18,221	$2,095,285	$25,979	$2,139,484
PIPING			$1,112,930		$2,054,724	$3,167,654
INSULATION				$4,974,728		$4,974,728
INSTRUMENTATION			$336,615		$82,821	$419,436
ELECTRICAL			$3,524,465	$1,091,328	$6,084,143	$10,699,936
START-UP, TEST & SERVICE			$25,300	$345,100	$779,860	$1,150,260
Total Direct Cost		**$118,043,596**	**$11,265,657**	**$19,366,814**	**$45,029,740**	**$193,705,807**

BURNS & McDONNELL ESTIMATE	CM / General Conditions - Escalated		$15,400,000
	Engineering Incl Expediting, Const. Support & Start-Up - Escalated		$23,000,000
	Escalation of Equipment	8% /yr	$8,368,697
	Escalation of Materials	8% /yr	$3,631,171
	Escalation of Labor	5% /yr	$7,295,086
	Taxes		$0
	Total Indirect Cost		**$57,694,954**
	Sub-Total		**$251,400,761**
	Estimate Accuracy Contingency	15%	$37,710,114
	Project Definition Contingency	10%	$25,140,076
	Total		**$314,250,951**
	Owner Costs		$8,372,000
	Owner Cost Escalation	6% /yr	$943,868
Date 11/11/2008 7:49	**Total Project Cost**		**$323,566,818**

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5.6 SUMMARY COST ITEM DESCRIPTION

The cost estimate is based on the multiple contracting approach defined in Section 3.0 – Contracting Approach. Additional mark up costs have been included for equipment, labor and material assumed subcontracted.

The contracting approach was developed concurrently with the cost estimate and the summary cost estimate is not broken down by Contract. The Summary Cost Item Description included at the end of this section defines scope included in each cost estimate line item.

5.7 MAJOR EQUIPMENT QUOTATIONS – FGD AND SCR

Multiple project specific vendor budgetary estimates were requested and received for the Cooper Unit 2 Environmental Project. The major equipment quotes for the CFB scrubber, fabric filter, SCR reactor and recommended boiler modifications have been included at the end of this section.

5.8 LABOR STUDY REPORT

A project specific Area Labor Study was prepared by Schumacher Consulting, LLC and is included at the end of this section.

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East Kentucky Power Cooperative
Cooper Station, Unit 2
Environmental Project

Capital Cost Estimate Basis and Assumptions

General Project Information:	
Project Description:	Unit 2 AQCS installation for NOx, SO_2, and particulate matter control to meet consent decree emission level requirements.
Plant Description:	Nominal 225 MW net pulverized coal AQCS design assumes installation of Unit 2 boiler and turbine upgrades.
Type of Plant:	Utility grade reliability.
Performance Fuel:	Bituminous Coal, Williams Illinois #6, 11801 Btu/lb, 10.97% moisture, 8.22% ash, 2.81% sulfur.
Design Fuel:	Bituminous Coal, Daron #8 , 12325 Btu/lb, 4.69% moisture, 11.59% ash, 4.31% sulfur.
Heat Rejection:	Lake Discharge or Cooling Towers.
Operation:	Base load with outages for maintenance.
Capacity Factor:	85%.
Minimum Load Capability:	40%
Project Location:	Existing Cooper Station near Somerset, KY.
Site Description:	Brownfield.
Project COD date:	June 30, 2012. AQCS must be operational 30 days prior to establish 30 day rolling average emission rates.
Labor Type:	Union.
Labor Incentives:	Per diem / safety / job completion.
Project L/Ds:	Schedule and Performance for each contract.
Contracting Method:	Multiple Contract.
Scope Basis / Assumptions:	
General:	
Water Supply:	
Water Intake:	Existing Lake Cumberland intake structure. Additional water capacity for AQCS to be taken from the low pressure lake water system.
Cooling Tower Makeup:	No modifications are included.
Service Water:	No modifications are included.
Potable Water:	Supplied from the existing potable water system. No modifications are included.
Wastewater Disposal:	
Cooling Tower Blowdown:	No modifications are included.
Wastewater Sump:	Included for AQCS area. Sump wastewater will be sent to the coal pile run-off pond.
Scrubber Process Wastewater:	Water added to dry scrubber process will be removed with CFB waste product and sent to landfill.
Contaminated Wastewater:	Drains from the area around new equipment that could be contaminated with oil will be directed to AQCS sump.
Sanitary Wastewater:	No new sanitary facilities are required.
Stormwater Discharge:	Existing stormwater drainage system will be modified as required for new structures. Stormwater from new structures will drain to AQCS sump.
Start-up Fuel:	Fuel Oil.
Solid Fuel:	
Delivery:	Solid fuel is delivered to the plant by truck. No modifications to existing system are included.
Dead Storage:	Solid fuel is stored in uncovered outdoor piles in the existing coal storage system. No modifications to existing storage system are included.
Live Storage:	Live storage is provided using the existing stock out/reclaim system with open piles. No modifications to the coal yard system are included.
Alternative Fuel:	No modifications for alternate fuels are included.
Lime Dust Supply:	
Type:	Pebble lime dust.
Delivery:	Pneumatic truck w/self contained unloading blowers.
Storage:	Silo sized for 150 tons pebble lime dust storage. No long term storage is included.
Lime Supply:	
Type:	Pebble lime.
Delivery:	Pneumatic truck w/self contained unloading blowers.
Storage:	Silo sized for 1400 tons pebble lime storage. Approximately 88 hours storage at 100% design fuel burn rate. No long term storage is included.

Fly Ash / CFB Waste Product Handling:	
Existing Dry ESP:	Assumed to be abandoned in place.
Disposal:	Air slide conveying system will remove waste product from the fabric filter hoppers to waste product surge bins Waste product will be removed from surge bins by new waste product removal vacuum system and disposed of in on-site landfill Estimated CFB waste product production, provided by Babcock Power Environmental, at 100% design fuel burn rate is 43 tph for Unit 2.
Storage:	Two new waste product silos are included to be used with existing fly ash silos to store CFB waste product from Unit 2 and fly ash from Unit 1 Silos sized for 1750 tons each, approximately 88 hours of storage at 100% design fuel burn rate.
Transportation:	Existing truck load out facilities will be expanded to encompass two new waste product silos for on-site disposal.
Bottom Ash:	
Disposal:	No modifications to existing bottom ash disposal.
Storage:	No modifications to existing bottom ash storage.
Transportation:	No modifications to existing bottom ash transportation.
Ammonia:	
Type:	19% aqueous ammonia.
Delivery:	Truck with self contained pump.
Storage:	Tanks sized for 380 tons of storage Approximately 10 days storage at 100% design fuel burn rate.
Civil:	
Site Conditions:	Extensive structures, foundations, concrete slabs-on-grade and circulating water pipelines are located in the AQCS area.
Layout Considerations:	Maintenance access roads, coal pile, circulating water lines, and proximity to Lake Cumberland.
Disposal of Spoils:	Spoils will be disposed of on site No hazardous materials are anticipated to be found in the soils.
Soil Conditions / Stability:	Existing soils are assumed to be stable in and around the area and suitable for use as lay down without any further preparation.
Subsurface Rock:	Subsurface rock is near existing grade for the Unit 2 AQCS area and consist of karst formation.
Cut & Fill:	Site is relatively flat. Minimal cut and fill will be required.
Dewatering:	Previous subsurface exploration did not encounter the water table It is assumed that an engineered dewatering system will not be required.
Construction Stormwater Control:	Silt fences will be required for construction erosion control No other special erosion control is included
Roads:	Existing roads east of Unit 2 will be rerouted as necessary to provide access to new AQCS. No other modifications to existing roads are included.
Parking:	No modifications to existing facilities are included.
Rail Scale:	Not included.
Truck Scale:	Not included.
Coal Pile Run-off:	Allowance included for modifications to coal pile run-off pond to increase detention capacity for AQCS wastewater No modifications to existing coal storage area are included.
Ash Landfill:	An allowance for an on-site landfill is included in Owner's Costs.
Site Security:	Site security is existing A chain link fence will be installed at the construction laydown areas as required.
Future Expansion:	Included in the site plan are considerations for future rail expansion, wet FGD system, Unit 1 SCR and dry FGD system, and material handling upgrade.
Landscaping:	Minimal landscaping is included. Disturbed areas will be seeded for erosion control.
Rail Access:	No modifications to existing on-site rail spurs are included.
Truck Access:	Existing roads will be used for construction access. No upgrades are included.
Structural:	
Soil Bearing Capacity:	Soil boring data from original Unit 1 construction was evaluated to estimate foundation design basis A geotechnical study is included to determine foundation design recommendations for detailed design Bearing capacity is assumed to be 10 ksf It is expected that all major foundations and minor foundations (buildings, tanks, etc) will be spread footings or mats.
Soil Improvement:	Project site is located in a karst subsurface area Subsurface consists of an uneven bedrock surface with a soil overburden Any soil filled crevices within the bedrock at the foundation bearing elevation will be removed and filled with lean concrete Soil filled crevices are assumed to be 50% of the volume extending 5 feet below the bearing surface Rock probes extending 10 feet below the foundation bearing surface will be drilled to confirm quality of rock beneath the foundations A minimum of one probe will be performed at each foundation and for each 75 square feet bearing area.

Piling:	No piling is included.
Groundwater:	No engineered dewatering system is included.
General Enclosures:	
Ash Load Out:	Existing ash load out enclosures will be expanded to include new waste product silos. Vacuum blowers to be located in new building adjacent to waste product silos.
Fabric Filters:	The Fabric Filter penthouse will be enclosed with metal wall panel. The Fabric Filter area below the hoppers will be concrete paved and enclosed with metal wall panel.
Scrubber:	Scrubber will be enclosed at its base and water lances will be enclosed.
Fans:	ID fans will not be enclosed.
Water Treatment Facilities:	Screen filters will be located in existing boiler enclosure.
Administration Facilities:	Not Included.
Control Facilities:	Existing control room will be used with an additional control console added for the AQCS.
Warehouse Facilities:	Allowances included in Owner's Costs.
Maintenance Shop:	Not Included.
Yard Maintenance Building:	Not Included.
Electrical Enclosures:	An electrical PCM enclosure is included.
Stack:	Existing masonry liner with concrete shell chimney will be used. No modifications are included.
Mechanical:	
Boiler Manufacturer:	Babcock & Wilcox.
Turbine Manufacturer:	General Electric.
Boiler Modifications:	Modifications to the superheat and reheat tube sections are included in order to burn the design coal.
Boiler Implosion:	Allowance included for study and mitigation.
Fans:	
FD Fans:	2x50% motor driven centrifugal fans with variable frequency drives.
PA Fans:	2x50% motor driven centrifugal fans. Single speed.
ID Fans:	2x50% motor driven centrifugal fans with variable frequency drives.
Economizer:	Economizer modifications are included to relocate lower bank of economizer tubes downstream of SCR in order to maintain required SCR inlet temperature ranges.
Air Heaters:	1x100% tri-sector air heater.
Soot Blowers:	Steam soot blowers included for economizer tube bank downstream of SCR.
Pumps:	
Boiler Feed Pumps:	Not Included.
Condensate Pumps:	2x100% condensate pumps are included for Ammonia system condensate return.
Circulating Water Pumps:	Not Included.
Sump Pumps:	2x100% wastewater sump pumps are included for AQCS sump.
Service Water Pumps:	2x100% water supply pumps are included to supply water for dry FGD system.
Water Treatment:	
AQCS Service Water:	2x100% screen filters.
Steam Cycle Make-up:	Not Included.
Cooling Tower Make-up:	Not Included.
Service Water Make-up:	Not Included.
Condensate Polishing:	Not Included.
Compressed Air Supply:	2x100% capacity air compressors with desiccant type air dryers are included for AQCS service and control air.
Fire Protection:	Fire protection will be tied into the existing fire protection loop. No new pumps are included. Fire protection equipment allowance is included.
Fire Detection:	Fire detection is included in the electrical areas.
Water Make-up:	
Supply Pumps:	No modifications to existing plant water supply.
Water Storage:	
AQCS Service Water:	Storage tank included. Sizing based upon 1 hour of water requirements at 100% design fuel burn rate.
Condensate Storage:	Not included.
Raw Water Storage:	Not included.
Demineralized Water Storage:	Not included.
Potable Water Storage:	Not included.
Auxiliary Cooling:	No modifications to existing system included.
Coal Handling:	No modifications to existing system included.
Lime Dust Handling:	Lime dust will be feed as needed by a screw feeder onto coal conveyor to control arsenic levels in the flue gas.
Lime Handling:	
Preparation:	Lime does not require preparation for storage in lime silo. Lime is reduced in size by hammer mill to approx. 1/4" before entering hydrator.

Dry Scrubber:	
Hydrator:	2x100% Hydrators
Scrubber:	1x100% Dry circulating fluidized bed scrubber.
Waste Product Recirculation:	Waste product recirculation system will include 2 air slide conveyors, 1 for each row of PJFF hoppers.
Waste Product Removal:	Three waste product surge bins, 1 per air slide, 1 for scrubber, are included and sized for 2 hours storage capacity. Waste product is removed from surge bins by vacuum removal system as described in the General section.
Fabric Filter:	
Type:	Pulse Jet Fabric Filter.
Redundancy:	Fabric Filter includes one spare cell to facilitate maintenance.
Emissions Control:	
Emissions Control:	
NOx:	Selective catalytic reduction to accomplish emissions of 0.07 lb/MMBtu NOx particulate.
Ammonia Slip:	Not expected to be regulated. Target 2 ppm at end of catalyst life.
CO:	Assumed to be controlled through good combustion practices.
SOx:	Dry CFB scrubber to accomplish emissions of 95% reduction or 0.10 lb/MMBtu.
PM10:	Fabric Filter to accomplish emissions of 0.015 lb/MMBtu filterable particulate and 0.005 condensable particulate.
Mercury:	No mercury control equipment is included. Inherent mercury removal is anticipated in scrubber and fabric filter.
Emissions Monitoring:	A new Unit 2 inlet CEMS shelter with SO_2 and CO_2 monitoring will be installed near the inlet duct of the scrubber. Communications and limited hardwired signals will be interfaced to the DCS and existing DAS. A new Unit 2 outlet CEMS shelter with SO_2, NOx, CO_2, Flow, and Opacity will be installed. Mercury CEMS will also be provided. Communications and limited hardwired signals will be interfaced to the DCS and existing DAS. A new Unit 1 particulate monitor will be installed in the Unit 1 duct prior to the common stack.
Stack Height:	Existing stack height: 260 feet.
Electrical:	
Generator Step-up Transformers:	No modifications.
Black Start Capability:	Not included.
Emergency Generator:	No modifications included.
Emergency Power:	4 hour DC system with a UPS for supply to the AQCS control system and critical instrumentation.
Back-up Power:	No modifications included.
Synchronization:	No modifications included.
Start-up Power Supply:	No changes will be made to the startup power supply. A connection will be made from the common bus to the new 4.16kV AQCS switchgear to provide a backup source in the event that both auxiliary transformers are unavailable.
Auxiliary Power Supply:	A new generator circuit breaker will be installed in the isophase between the generator and the auxiliary transformer tap. Two new auxiliary Transformers will be connected to the isophase between the GSU and the new generator circuit breaker. The transformers will be supplied as three winding transformers with a 20kV high-side winding and two 4.16kV low-side windings. One 4.16kV winding will be sized for the full load ampacity of the existing aux transformer (13MVA). The other 4.16kV winding will be sized based on an AQCS switchgear bus rating of 2000A. The estimated size of this winding assumes that variable frequency drives will be used on the ID fans.
Switchgear Design:	A new 4.16kV switchgear lineup, in a main-tie-main configuration, will be provided to service the new AQCS loads and ID Fans. The existing ID fan breakers located on switchgears 2A and 2B will be spared. Feeds for the new FD and PA fans assumed to be from the existing plant switchgear.
Low Voltage Switchgear Design:	Low voltage switchgear configured in a main-tie-main configuration will be supplied for the AQCS low voltage loads. The switchgear will be fed from new station service transformers via non-seg bus.
Low Voltage Motor Control Center Design:	New motor control centers will be supplied for the AQCS low voltage loads. MCC's will be fed from the AQCS 480V switchgear with the exception of MCC's for fly ash and ammonia. These MCC's will be connected directly to 4.16 - 0.48kV station service transformers which will be equipped with main breakers.
Plant Control System:	The existing ABB DCS will be expanded and modified to support the additions and modifications for the ID Fans by adding remote IO that is controlled by the boiler controller. Additional ABB DCS controllers and IO will be installed to monitor and control Pebble Lime Preparation, Fly Ash removal, CFB Scrubber, Fabric Filter, Ammonia systems, and Balance of Plant scrubber systems. Individual systems requiring exclusive PLC or local control systems, such as fabric filter control, ammonia system, air compressor, and CEMS will be supplied with the equipment and interfaced to the DCS for monitoring and supervisory control through soft communications and limited hard wire connections.

Wire Routing:	Cable tray is assumed to be used in locations of overhead structural steel and ductbank is included for all other locations.
Plant Communications:	
External and Office to Office:	No modifications included.
Internal Around Plant:	Gaitronics communication system throughout the AQCS upgrade equipment.
Switchyard Communications:	No modifications included.
Transmission / Interconnection:	
Switchyard:	No modifications are included.
Transmission:	No modifications are included.
Commercial:	
General Liability Insurance:	Included.
Builder's Risk Insurance:	Not included.
Performance Bonds:	Bonds are included for 100% of labor for all construction contracts. No bonding is included for Owner-furnished equipment contracts.
Project L/Ds:	Schedule and Performance for each contract.
Retention:	A 10% retention will be required on all contracts.
Warranty:	Warranty on major equipment will be required for 1 year from commercial operation. Warranty on auxiliary equipment will be required for 18 months from substantial completion to the extent practical.
Construction Indirects:	
Performance Testing:	Allowance included for all major components regardless of contracting approach.
Commissioning / Start-up:	Allowance included.
Permits:	Construction permits are included.
Construction Utilities:	
Water Supply:	Water supply for construction will be from the existing water system.
Construction Sanitary Facilities:	Portable facilities provided by construction contractors.
Construction Power:	Power supply for construction will be from the existing common bus. A spare breaker on the common bus will serve as the construction power feed. Following construction, this feed will serve as the backup feed for the 4.16kV AQCS switchgear. Transformer for power supply is assumed to exist or to be available as extra capacity in the startup transformers. Cost of power consumption is not included.
Equipment Delivery:	Equipment will be delivered to the site via truck.
Construction Schedule:	It is assumed that the construction schedule will be adequate to allow the project to be completed with minimal overtime. Construction schedule will be estimated as a 5x10 schedule to provide an incentive to attract labor.
Construction Facilities:	Rental buildings with temporary E&CM building.
Project Indirects:	
Project Development:	Allowance included.
Owner's Operations Personnel:	Allowance included.
Owner's Project Management:	Allowance included.
Owner's Engineering:	Allowance included.
Owner's Legal Council:	Allowance included.
Operator Training:	Allowance included.
Permitting & License Fees:	Allowances for Air, NPDES, and other plant discharge permits are included.
Wetland Mitigation:	Allowance included.
Landfill:	Allowance included.
Land:	N/A
Water Rights Costs:	N/A
Labor Camp:	N/A
Initial Lime Inventory:	Allowance included.
Initial Ammonia Inventory:	Allowance included.
Site Security:	Allowance for project specific security included.
Operating Spare Parts:	Allowance included.
Permanent Equipment & *Furnishings:*	
Workshop Tools & Test Equipment:	Allowance included.
Warehouse Shelves:	Allowance included.
Mobile Equipment, Vehicles:	Allowance included.
Laboratory Equipment & Furniture:	Allowance included
Kitchen Furniture:	Not Included.
Locker Room Furniture:	Not Included.
Building Furniture:	Allowance included.

Sales Tax:	Not Included.
Escalation:	Escalation included to COD at a rate of 5% for labor, 8% for materials, and 6% for Owner's costs per year.
Contingency:	Contingency of 15% is included for estimate accuracy and 10% for project definition.
All Owner's Costs:	Provided by EKPC for inclusion into the cost estimate by BMcD.
Cost Estimate Exclusions:	
Costs Not Included In the Estimate:	
1. Taxes including sales, use, gross receipts, property and any other types.	
2. All insurance other than General Liability, including but not limited to Builders Risk insurance.	
3. Electrical interconnection costs and transmission system upgrades beyond the high side of the GSU.	
4. Sound abatement above normal supply.	
5. Aesthetic landscaping other than erosion control.	
6. High escalation associated with extreme market conditions.	
7. Financing fees.	
8. Interest during construction.	
9. Demolition of existing precipitator, ID fans, FD fans, PA fans, and air heaters.	
10. Repairs or modifications to existing stack.	

PRELIMINARY COST ESTIMATE SCOPE SUMMARY
EAST KENTUCKY POWER COOPERATIVE
COOPER STATION UNIT 2 AQCS
B&McD PROJECT 50198
SOMERSET, KENTUCKY

FGD & FABRIC FILTER
- CFB Scrubber
- Fabric Filter
- Elevator
- Hydrators
- Hydrated Lime Silo
- Water Storage Tank
- FGD & FF Equipment Support Steel

ID FANS
- ID Fans
- ID Fan Motors
- ID Fan Lube Oil Skids

WASTE PRODUCT SYSTEM
- Waste Product Transfer Equipment
- Waste Product Silos
- Waste Product Piping

DUCTWORK
- Ductwork

SCR
- SCR Reactor
- Ammonia Injection Grid
- SCR Catalyst

AMMONIA SUPPLY EQUIPMENT
- Ammonia Supply Equipment to Injection Grid
- Ammonia Storage Tanks

FE TANKS
- Pebble Lime Silo

MISC PUMPS & EQUIPMENT
- Miscellaneous Pumps
- Air Compressors

WATER TREATMENT SYS
- Filters
- Forwarding Pumps

ELECTRICAL EQUIPMENT
- Generator Circuit Breaker
- Iso-Phase Bus
- ID Fan Variable Frequency Drives
- Non-Seg Bus

4.16KV Switchgear
480V Switchgear
Motor Control Centers
UPS and DC System
Power Control Module Enclosure

TRANSFORMERS
Auxiliary Transformers
Small Power Transformers

DCS MODIFICATIONS
DCS Modifications

CEMS
Continuous Emission Monitoring System

BOILER & AIR HEATER MODS
Coal Conveyor Lime Feed System
New Air Heater, FD and PA Fans
Economizer Modifications
Reheat and Superheat Modifications
Boiler Implosion Study and Modifications

CIVIL
Civil - Labor and Material Subcontract

STEEL
Steel - Labor and Material Subcontract

CONCRETE
Concrete - Labor and Material Subcontract

ARCHITECTURAL
Architectural - Labor and Material Subcontract

PIPING
Piping - Labor and Material Subcontract

INSULATION
Insulation - Labor and Material Subcontract

INSTRUMENTATION
Instrumentation - Labor and Material Subcontract

ELECTRICAL
Electrical - Labor and Material Subcontract

PRELIMINARY COST ESTIMATE SCOPE SUMMARY
EAST KENTUCKY POWER COOPERATIVE
COOPER STATION UNIT 2 AQCS
B&McD PROJECT 50198
SOMERSET, KENTUCKY

START-UP, TEST & SERVICE

- Craft Start-Up
- Performance and Construction Testing
- Geotech
- Surveying and Trenching
- Model Study

babcock & wilcox power generation group
20 south van buren avenue · p.o. box 351 · barberton, oh 44203-0351 usa
phone 330 753 4511 · fax 330.860 1886 · www.babcock.com

October 7, 2008

Mr. John Meinders
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Subject: Replacement Burners w/ OFA Budgetary Proposal
EKPC Cooper Unit 1 (RB-389) and Unit 2 (RB-437)
B&W Contract No.: 591-0933

Dear John:

Babcock & Wilcox Power Generation Group (B&W) is pleased to submit budgetary pricing for the material supply to replace the existing burners for East Kentucky Power Cooperative (EKPC) Cooper Station Units 1 and 2. These budgetary costs are to facilitate your evaluation and give order of magnitude pricing for EKPC's upcoming Board meeting.

Scope

Unit 1 RB-389

- Nine (9) B&W DRB-XCL-HV burners
- Nine (9) new tile throat assemblies
- Five (5) OFA ports with registers and furnace bent tube openings
- Existing front wall windbox will be extended up to supply the OFA ports
- Delivery F.O.B. Cooper Station

Note that the existing burner pressure part openings, burner drives, ceramic coal lined elbows, ignitors, scanners and support rails will be re-used.

Unit 2 RB-437

- Eighteen (18) B&W DRB-XCL-HV burners
- Eighteen (18) new tile throat assemblies
- Eight (8) OFA ports with registers and furnace bent tube openings
- New OFA plenum and ducts to supply the OFA ports located on the furnace rear wall
- Delivery F.O.B. Cooper Station

Note that the existing burner pressure part openings, burner drives, ceramic coal lined elbows, ignitors, scanners and support rails will be re-used.

Items NOT Included

- Installation of the burners and OFA ports
- Start-up, training and testing services
- Electrical and controls modifications

Budgetary Pricing (USD 2008)

• Budgetary Material Pricing for Unit 1	$596,000.00
• Budgetary Material Pricing for Unit 2	$1,010,000.00

Schedule

- Approximately 50 weeks from receipt of an acceptable Purchase Order to delivery FOB Cooper Station.

Clarifications

- Note that many of the coals considered in the study are high in sulfur content and present a risk for furnace wall corrosion with staged operation. Weld overlay on the furnace walls on both units (and to the division walls on Unit 2) is recommended for these coals.
- Changes in overall burner/NOx port resistances will need further evaluation in the future relative to pressure drops for the existing burners at the same operating conditions. Both units have been converted from pressured fired to balanced draft, so FD fan static may not be a problem if the original FD fans and motors are still being used.
- The budget price and schedule are based on current availability of raw material, engineering and manufacturing resources.
- B&W standard manufacturing and quality standards apply.
- B&W standard commercial terms and conditions apply.
- Material delivery to site is included.

Please note that we have quoted these prices in 2008 dollars, and did not attempt to project an escalation rate for time of performance or delivery. In recent years, escalation of the raw materials required to fabricate our boiler products has not followed a predictable escalation rate.

This budgetary proposal is considered B&W proprietary and confidential and does not represent an offer to sell; however, we would welcome the opportunity to firm up our pricing upon request.

We thank you for the opportunity to provide this budgetary pricing. If you have questions or comments regarding our proposal, please feel free to contact Dan Krekeler or Mike Fick.

Sincerely,

Michael D. Fick
Project Manager
Service Projects
Telephone: 330-860-2676
Email: mdfick@babcock.com

cc: Brian Basel – Burns & McDonnell
Von Steiner – Burns & McDonnell
Mary Jane Warner – East Kentucky Power Cooperative
Scott Gossard – B&W Barberton, BT32
Dan Krekeler – B&W Sales, Cincinnati

babcock & wilcox power generation group
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▸ phone 330 753 4511 ▸ fax 330 860 1886 ▸ www.babcock.com

October 9, 2008

Mr. John Meinders
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Subject: Boiler Pressure Parts Budgetary Proposal
EKPC Cooper Unit 1 (RB-389) and Unit 2 (RB-437)
B&W Contract No.: 591-0933

Dear John:

Babcock & Wilcox Power Generation Group (B&W) is pleased to submit budgetary pricing for the material supply to modify the existing boiler pressure parts for East Kentucky Power Cooperative (EKPC) Cooper Station Units 1 and 2. These budgetary costs are to facilitate your evaluation and give order of magnitude pricing for EKPC's upcoming Board meeting.

Scope

Unit 1 RB-389

- Addition of 8 rows of primary superheater surface and header to increase main steam temperature at reduced load conditions.
- Option for economizer bank and piping located downstream of SCR to improve boiler efficiency.
- Delivery F.O.B. Cooper Station.

Unit 2 RB-437

- Addition of 18 rows of primary superheater surface and header to increase main steam temperature at reduced load conditions.
- Replacement of 3 rows of the reheater outlet bank due to material oxidation limits being exceeded.
- Option for economizer bank and piping located downstream of SCR to improve boiler efficiency.
- Delivery F.O.B. Cooper Station.

Note that the scope of the Engineering Study did not include a review of plant data, auxiliary equipment (fans, pulverizers, etc), attemperator system, air heater costs, emissions, installation and costs, balance of plant, AQCS systems, fuel handling system, and ash handling system.

Before any future convection pass modifications are made, B&W recommends a detailed review of plant data to calibrate the boiler models.

Items NOT Included

- Installation of the pressure parts
- Demolition of existing economizer pressure parts
- Structural steel & foundations for Option economizer located downstream of SCR's
- Start-up, training and testing services

Budgetary Pricing (USD 2008)

• Budgetary Material Pricing for Unit 1	$855,000
• Budgetary Option Economizer Pricing for Unit 1	$890,000
• Budgetary Material Pricing for Unit 2	$2,205,000
• Budgetary Option Economizer Pricing for Unit 2	$1,585,000

Schedule

- Approximately 65 weeks from receipt of an acceptable Purchase Order to delivery FOB Cooper Station.

Clarifications

- The existing boiler convection pass pressure parts enclosure and casing will be re-used.
- The budget price and schedule are based on current availability of raw material, engineering and manufacturing resources.
- B&W standard manufacturing and quality standards apply.
- B&W standard commercial terms and conditions apply.
- Material delivery to site is included.

Please note that we have quoted these prices in 2008 dollars, and did not attempt to project an escalation rate for time of performance or delivery. In recent years, escalation of the raw materials required to fabricate our boiler products has not followed a predictable escalation rate.

This budgetary proposal is considered B&W proprietary and confidential and does not represent an offer to sell; however, we would welcome the opportunity to firm up our pricing upon request.

We thank you for the opportunity to provide this budgetary pricing. If you have questions or comments regarding our proposal, please feel free to contact Dan Krekeler or Mike Fick.

Sincerely,

Michael D. Fick
Project Manager
Service Projects
Telephone: 330-860-2676
Email: mdfick@babcock.com

cc: Brian Basel – Burns & McDonnell
Von Steiner – Burns & McDonnell
Mary Jane Warner – East Kentucky Power Cooperative
Scott Gossard – B&W Barberton, BT32
Dan Krekeler – B&W Sales, Cincinnati

LLIED
ENVIRONMENTAL SOLUTIONS, INC.

Allied Environmental Solutions

BUDGETARY CIRCULATING FLUID BED SCRUBBER PROPOSAL

To

Burns and McDonnell

For

Eastern Kentucky Power Cooperative Units 1 and 2

Rev. 0

October 06, 2008

TABLE OF CONTENTS

SECTION 1

INTRODUCTION

Allied Environmental Solutions (Allied) is pleased to present this budgetary proposal to Burns and McDonnell for the Eastern Kentucky Power Cooperative project.

Please note that Allied is proposing use of a CFB Scrubber with a pulse jet fabric filter (PJFF) for each of the facilities as this is what is specified in the RFQ. Note that Allied can provide an ESP for particulate collection in lieu of a PJFF if this is desirable. The acid gas and lime consumption guarantees will be unchanged if an ESP is used in lieu of a PJFF. The capital cost is similar to a PJFF, and well within the budgetary tolerances. Additionally, it may be possible for Allied to reuse the existing particulate control devices which would allow for a significantly lower cost. Allied would need additional information regarding the sizing and performance of the existing devices and additional site layout drawings to be able to assess this formally.

A few specific notes regarding this offering:

1. For lime consumption purposes, Allied has assumed 100% of the fuel fluorine enters the scrubber as HF. As no chlorine was specified Allied assumed that it is present at 4 times the mass flow of the fluorine. Inlet particulate loading to the scrubber was calculated based on the coal analysis provided and assumed a 90% carryover from the boiler. Also, as no inlet SO_3 was specified Allied assumed 2% conversion of the SO_2 on a mass basis. Inlet SO_3 values (once known) will also need to assessed to see if there are any localized APH exit acid attack concerns.
2. GA drawings are included for both units based upon other Allied projects of a similar size.
    a. Unit 1's scrubber and baghouse are very similar in size to a unit we proposed previously on another project and this GA is attached. Note that the unit shown is slightly larger than required (for example, this shows a 21'-6" scrubber diameter vs. the 20' required here). Please note that Unit 1 is almost exactly the same size as our Georgia Pacific, Port Hudson facility, which went in service last year and which uses an ESP for particulate control. The proposal does not list details of the ESP as the RFQ specifically stated a baghouse requirement but if this possibility is of interest to you or your client we would be pleased to present more information. We have included the Port Hudson GA showing an ESP for your consideration.
    b. Unit 2's scrubber and baghouse are EXACTLY the same size as our PPGA Whelan Energy Center project currently under execution. Accordingly we are provided the PPGA GA for as correct for Unit 2.
    c. Note that in both of the above the various tanks, bins and silos have not been modified on the drawing to reflect actual sizing for this project. The water tank and ash bins should be very close but the lime silos will be much larger on these units than are shown on the drawing as the SO2 loadings and removal percentage requirements are very high. The correct silo sizings (diameter x straight wall height) for each unit are as follows, assuming 4 days of storage in both the hydrate and pebble silos.
        i. Unit 1 – Hydrate Silo 40' dia x 120' straight wall. Pebble Silo 35' dia x 110' straight

ii. Unit 2 – Hydrate Silo 53' dia x 150' straight wall. Pebble Silo 47' dia. X 130' straight

Our experience shows that silos of this size are difficult to fabricate from steel as the bottom portion of the silo is made from steel thicker than can be easily rolled. Allied therefore suggests that these silos be concrete and supplied by others. *Please note that this is a change from the preliminary scope of work document sent on 9/25.*

3. The provided electrical load list and instrument list are taken from the PPGA Whelan project and are therefore good to assume for use for Unit 2. The loads shown will therefore be somewhat conservative for Unit 1. The instrument list is valid for both Units as-is.
4. The requested emissions guarantees can be offered with no problems whatsoever.
5. For this proposal a hydrator system is included as specified. Allied is proposing our standard design for this hydrator, which includes a 1 x 100% capacity hydrator system for each train. In case of hydrator failure, the fill line on the hydrated lime silo can be used. This avoids the significant capital cost associated with the addition of a second hydrator system. This approach has been successfully used since 1995 at Allied's BHP&L Neil Simpson Unit 2 project and will be utilized on the PPGA Whelan Energy Center project that Allied is currently executing. By sizing the hydrated lime silo for 4 days, this hydrated lime silo is truly a "100% spare hydrator" in effect.
6. Baghouse sizing assumes that "net" condition operation is desired up to the gas flow rates specified (i.e. without derating the boilers). If this is not required the baghouses can be made to be smaller.

Allied's CFB scrubber represents the "next generation" dry scrubbing technology and has numerous advantages over spray dryer absorber (SDA) technology. Some of these advantages are:

<u>Performance:</u>

- Capable of achieving and guaranteeing 99%+ SO_2, HCl, HF and other acid gas removal rates
- CFB scrubber can significantly increase SO_2 emissions performance, if required due to air permit changes, for little if any additional capital costs, and can meet any foreseen changes in air permits.
- Virtually infinite turndown with the use of our patent pending flue gas recirculation system (not included at this time, pending definition of the low load design case)
- Ability to utilize either a PJFF or ESP as the downstream particulate control device for the same emissions performance
- Wet FGD equivalent performance at a fraction of the capital cost. All materials are mild steel, eliminating the need for expensive alloys and the associated specialty field welding

<u>Experience:</u>

- Only Allied has substantial North American operating experience with the CFB Scrubber technology
- Only Allied has North American experience with both PJFF's or ESP's downstream of the scrubber
- Only Allied can boast 30 PC fired boilers with CFB Scrubbers on a range of bituminous and sub-bituminous fuels.

Simplicity of Design:

- CFB scrubber does not require the maintenance intensive slakers as required by a spray dryer absorber (SDA) system resulting in lower O&M costs and higher system availability. The CFB design requires only a lime silo with proven gravity fed airslides to accomplish lime feed into the system.
- No slurries are created anywhere in the process.
- No high speed rotary or dual fluid nozzle atomizers or mechanical material handling systems are required as would be the case with an SDA that may possibly cause a boiler derate.
- Recirculated material stays inside the process, unlike rotary or dual fluid spray dryer.
- Ash recirculation system not subject to Al / Si abrasion as with an SDA.
- The CFB scrubber system has no stringent water quality requirements, and thus offers an effective way to dispose of plant wastewater streams

Operating & Maintenance Cost:

- Lowest cost ash handling system by the Owner
- Allied's system includes an ash handling system, minimizing the BOP ash handling costs. There are only three (3) pick-up points per train for the Owner's ash removal system.
- Fewer wear components in the CFB technology i.e. no high-speed rotary atomizers or dual fluid nozzles, mechanical material handling equipment and elimination of all slurry handling equipment, reduces the annual cost of replacement components.
- Real experience from plants operating these differing technologies side by side on power boilers conclusively show an operating cost savings of one full time person per shift when compared to SDA as well as significant annual O&M parts and labor costs savings.

SECTION 2

PROCESS DESCRIPTION

The Circulating Fluid Bed Scrubber (CFB) process represents a proven alternative to wet scrubbing. The process can achieve greater than 99% SO_2 capture on high (>6%) sulfur fuels with greater reliability and less maintenance than either the wet or semi-dry spray dryer (SDA) systems. The process is totally "dry", meaning it not only produces a dry free flowing disposal product but also introduces the lime reagent as a dry free flowing powder.

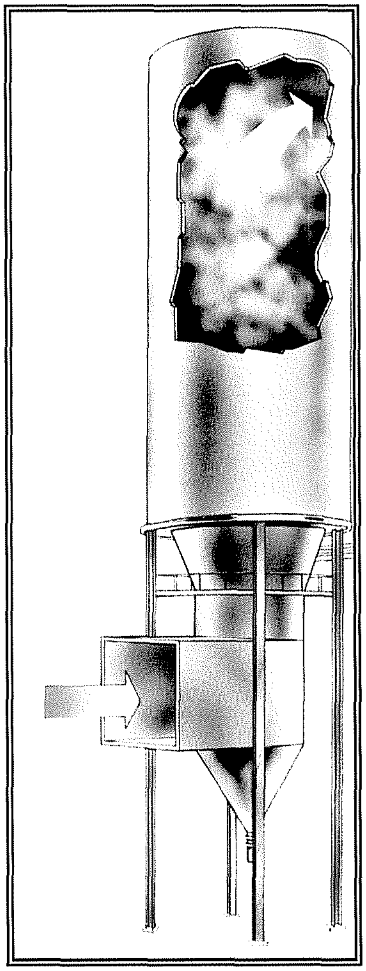


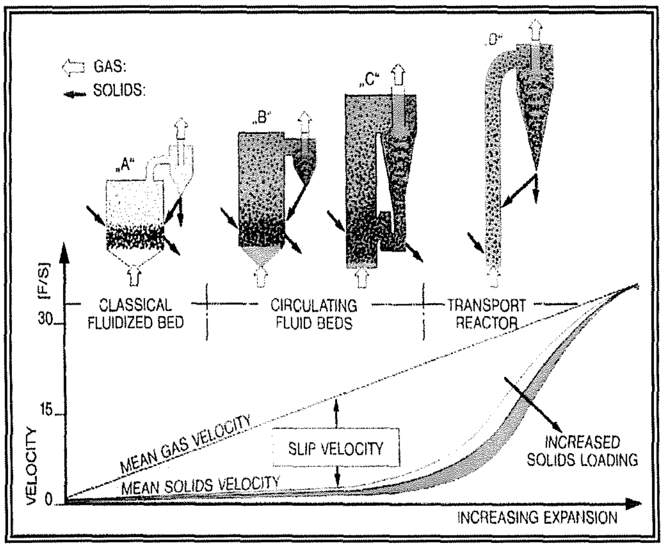
Figure 1: CIRCULATING FLUID BED SCRUBBER

Flue gas is directed into the bottom of the CFB vessel where it is turned upwards and passes through a grid of venturis. The lime reagent is introduced below the venturi level where it mixes with the flue gasses and gets evenly dispersed in the vessel via the mixing that occurs in the venturi throat. Above the venturis, cooling water is added which is totally independent from the introduction of fresh reagent and/or recirculated by-product. The CFB is completely empty and has no special internals that can be eroded or plugged. All vessel materials of construction are carbon steel. The utilization of reagent (calcium) is vastly improved over previous "dry" processes by evaporative cooling of the flue gas to within 30°F of adiabatic saturation and retaining the calcium in the process for an average of 30 minutes of contact (typically) with the SO_2. Cooling water spray is totally independent from the introduction of fresh reagent and recirculated by-product. Thus a totally dry process is successfully applied to higher sulfur dioxide concentrations than the semi-dry SDA process with demonstrated performance capabilities equivalent to or better than the "wet" process. Improved reliability and availability has been achieved by eliminating equipment requiring routine maintenance such as ball mills, slurry pumps, agitators, high-speed rotary atomizers, thickeners, and sludge dewatering equipment. By-product that is generated as a result of the CFB process is collected in a downstream electrostatic precipitator or fabric filter. The by-product is metered from the collector hoppers onto airslides that are designed to recirculate back into the scrubber vessel. A portion of this material is diverted from the hoppers and flows via gravity to a product surge bin, located at grade, and then into the ash handling system.

As is shown, the CFB operates not only as a chemical reactor for absorbing gaseous contaminations but also as an evaporator. Surface humidity of solids within the CFB is held nearly constant by maintaining the introduction of water completely independent of the recirculated solids and fresh lime. This eliminates the potential for scaling that exists in wet and semi-dry processes.

The excellent heat and mass transfer is achieved by maximizing the slip velocity between the solid particles and the flue gas (differential velocity).

For classical or bubbling flue fluidized beds the particle velocity is very close to the main gas velocity with which the bed is fluidized. Therefore, the "slip" is relatively small.



Transport reactors also operate with minimal slip velocity. The gas velocity is so high that the particles are entrained as nearly independent individual single particles. The particle and transport gas velocities differ only by the particle suspension velocity. Therefore the slip velocity is minimal.

In the expanded circulating fluid bed scrubber the slip between the average solids velocity and the fluidizing gas is a maximum. For fluidizing gas velocities in between the bubbling bed and transport reactor and at a sufficient solid loading, the particles are forming chains. This creates a different aerodynamic resistance and allows the solid chains to move contrary to the fluidizing gas until the slip velocity is so high that the chains will be destroyed and the single particles will again be entrained by the fluidizing gas. That explains the typical pulsation of an expanded CFB where the particles are continuously tumbling within the gas-solid suspension.

Typical CFB characteristics are:

- *High mass transfer rate within the lime particles*, which have an average particle diameter of 5 to 10 microns.
- *Extremely long solids retention time* that allows high concentrations of gaseous pollutants to be absorbed with very efficient lime utilization.
- *Continuous abrasion of the lime particle surface,* removing inactive CaSO4 surfaces which cover active lime particle cores.
- *Operating temperatures with a close approach* to the water dew point can be achieved which gives a high utilization of the reagent.

- *Wastewater can be used* for water injection, which improves desulphurization and dust collection. The water injection is independent from the reagent feed required for desulphurization.

- *The natural turndown ratio* is from 100% to 60% of the volumetric gas flow rate to the scrubber. Operation below this can be achieved through the use of clean-gas recirculation, or other means (not included).

The simplified process control effectively consists of only three major control circuits for fully automatic operation. This process is in principle very simple and reliable.

- SO_2 Control:
  The feed of hydrated lime is controlled by the amount of SO_2 in the flue gas which sets the basic predetermined lime rate for the absorber corrected by the SO_2 clean gas concentration.
- Temperature Control:
  The gas temperature leaving the absorber controls directly the amount of water that will be injected via high-pressure return flow nozzles into the bottom of the absorber. Repositioning the return flow valve will cause a change in the amount of water being sprayed into the CFB.
- Solids Discharge:
  The solids loading of the absorber control the amount of dry by-product discharged from the system. This is measured by the pressure loss along the absorber height and is kept on a constant value. The solids loading, or the hold up, divided by the solids feed (product and dust) gives the solids retention time of the absorber. It can be varied over wide ranges limited by the draft capability of the fan for the maximum value.

The reagent can be in the form of either powdered hydrated lime or pebble lime. For hydrated lime, the only equipment required is a storage bin, gravimetric belt feeder and an airslide conveyor. For systems that use pebble lime a hydrator that mixes the pebble lime with water would be required followed by a hammer or ball mill grinder to produce the proper particle size. An economic analysis of the total tonnage requirements and the local availability and price of these reagents will indicate which system is more cost effective.

SECTION 3

SCOPE OF WORK

Note: all quantities below are "per boiler" with one AQCS train required per boiler. Detailed sizing information for each train follows in the tables at the end of this section.

Scrubber:

- One (1) multiple venturi vessel with:
    - Sloped bottom with fluidization and 12" ANSI flange
    - Outlet duct to particulate collection device
    - Fabric expansion joints between the scrubber and the PJFF with liner
    - AR 400 or equal abrasion resistant steel for the venturi nozzles
    - ASTM A-514 or equal steel in high wear vessel wall areas (diverging section and 1st course of vessel straight wall) ¼" thick minimum
    - From 2nd course of vessel straight wall to PJFF inlet, ASTM A-36 mild steel 1/4" thick min.

Gas Humidification System:

- One (1) independent gas humidification system, complete with:
    - Closed top tank sized for 1-hour supply of cooling water
    - Two (2) x 100% capacity water pumps, motors with bases
    - Back-flow control valve, solenoid operated valves and dual basket strainers
    - Water spray lances/nozzles with quick disconnects (including one spare per vessel).
    - Water piping from the inlet to the water tank to the water spray lances.

Reagent System:

- One (1) Lime Preparation, Storage and Feed System sized for a nominal four (4) days storage at MCR conditions including:
    - 1 x 100% Pebble Lime hydration system including pebble lime weigh belt, hydrator (including high speed pre-mixer and low speed seasoning chamber), hydrated lime grinding and classifying system, and hydrate lime transport system to the Hydrated Lime Silo.
    - Double discharge from silo as follows:
        - Normal feed to de-aeration bin
            - Manual shut off knife gate valve
            - Automatic pneumatic slide gate valve
            - Rotary valve
        - Emergency feed to lime air slide
            - Manual slide gate
            - Rotary valve
    - De-aeration bin with pneumatic single outlet slide gate valve
    - Weigh belt feeder and variable speed rotary valve to lime air slide for normal operation

- Airslide to scrubber main airslides
- Note: Due to their size (see section 1) Pebble and Hydrated Lime Silos will be made of concrete and therefore supplied by others.

By-Product Recirculation & Removal System:

- One (1) By-Product Recirculation System consisting of:
  - Hopper bottom aeration
  - Hopper fluidizing air blowers and heaters, located at grade
    - 2 x 100% blowers
    - 4 heater banks (2 on + 1 for start-up + 1 spare)
  - Manual Knife Gate Valves
  - One (1) dosing valve per hopper
  - One (1) set of Overflow Discharge Pipes – inlet hoppers only
  - Expansion boots and chutes
  - Hopper level detectors – four (4) per hopper
  - Two (2) Airslide conveyors. One from each row of PJFF hoppers to the Scrubber
  - Airslide fluidizing air fans and heaters
    - 2 x 100% fans
    - 4 heater banks (2 on + 1 for start-up + 1 spare)
  - Airslide fluidizing air piping, valves fittings and supports
  - Two (2) Ash By-Product Storage Bins per PJFF sized for a total storage capacity of approximately two (2) hours.

Duct:

- Duct from Scrubber outlet to Fabric Filter inlet, including expansion joints and supports.

Piping:

- Design and supply of large bore (> 2-1/2") piping prefabricated (spooled) including supports, valves, regulators and filters.
- Large bore piping isometric drawings.
- Supply of random length of small bore piping (no isometric or routing drawings provided).

Primary Particulate Collection System:

- One (1) Pulse Jet Fabric Filter, consisting of:
  - One (1) fabric filter system of the structural walk-in plenum design with bags, cages, pulse pipes and pulse valves designed for continuous, automatic, negative pressure operation. Each compartment has 18 osy (nominal) singed, felted 2.7 denier PPS ("Ryton") bags that are nominally 24'-6" long and 6" in diameter and of the snap band type. Bag cages shall be three (3) piece and have 12 vertical wires, 9 gauge minimum, and shall be of mild steel construction with integral venturi. The unit is sized to allow "net" operation with one compartment off line for maintenance.
  - Inlet and outlet manifolds, 1/4" ASTM A-36

- ASTM A-514, or equal, abrasion resistant turning vanes at the fabric filter inlet.
- 1/4" ASTM A-36 casing
- 1/4" thick ASTM A-36 hoppers (60° valley angle) and tubesheet.
- Compartment inlet single blade louver (butterfly) dampers with pneumatic actuators
- Compartment outlet poppet dampers with pneumatic actuators.
- Two (2) 100% Air Compressors and receiver
- Hopper door, level detectors, poke tubes and strike plates
- Hopper heaters with thermostat controls, junction boxes and NEMA 4 control panel.
- Local instruments including thermocouples, pressure transmitters, tubesheet delta pressure gauges, and limit switches for position feedback on all dampers.
- Design of a control system that will interface with Owner's Distributed Control System.
- One (1) broken bag detector per compartment
- 3% spare bags
- 2% spare cages.
- Two Jib Cranes per unit. Hoists by others
- Grounding pads

Access, Platforms, Galleries:

- Design and supply of access platforms, galleries, stairs and/or ladders will be provided for all equipment supplied.

Support Steel:

- Design and supply of the scrubber vessel and lime silo support structure to grade that will allow for four (4) feet of clearance from the bottom of the ash discharge flanges to grade.
- Design and supply of the PJFF supports to grade.

Equipment Enclosures:

- Design and supply of framing and girts for equipment enclosures for the following areas:
  - Water injection lances into the scrubber
  - Hydrator system
  - Hydrated Lime silo discharge and metering equipment area
  - Water tank

Instrumentation and Controls:

- All instruments required for proper operation of the system shall be supplied.
- Logic only for system DCS control (DCS and remote I/O racks by others)

Painting:

- All insulated mild steel plate surfaces both inside and outside will receive no paint.
- Exposed steel surfaces, such as support steel, stub columns, clips and conduit supports will receive SSPC-SP6 treatment and 3 to 5 mils of a zinc rich primer, Carboline Zinc 11, or equal
- Access system (grating, stair treads) will be galvanized with painted supports and stringers.
- Field finish painting by others.

Gas Recirculation System for Low Load operation (Patent Pending):

- ¼" A36 duct, including supports and expansion joints.
- Control and isolation dampers
- All required instrumentation including flow measuring arrays and damper position indicators.

Drawings, Documentation and Design Services:

- Erection Drawings will be provided
- Operation & Maintenance Manuals will be provided
- Design, Drawings and Specifications for the Heat Insulation and Lagging System
- Isometric drawings for large bore (>2-1/2") piping are included.
- As-Built drawings from Customer's redlines
- DCS F.A.T. witness test and providing typical DCS graphics

Model Study:

- 1/12th scale Plexiglas model study from the A.H. Outlet to the stack inlet.

Freight:

- Truck freight of all supplied equipment, F.O.B. jobsite
- Trucks shall be standard size trucks

Field Services:

- Without knowing the erection and startup schedule, no firm price bid can be made regarding field services. At this time field services are excluded and will be provided on a per diem basis.

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Equipment Tabulation:

Parameter	Unit 1	Unit 2
Number of Scrubbers	1	1
Number of Operating Water Nozzles per Scrubber	3	3
Scrubber Diameter (ft)	20'	30'
Scrubber Wall Height (ft)	80'	100'
Number of Venturis/Scrubber	7	7
Number of FFs	1	1
Number of Compartments per Fabric Filter	6	6
No. of Bags per Compartment	720	1530
Bag Diameter (in)	6	6
Bag Length (ft)	24'-6"	24'-6"
Bag Material	18 osy PPS	18 osy PPS
Gross A/C Ratio (effective)	2.3 : 1	2.4 : 1
Net A/C Ratio (effective)	2.8 : 1	2.8 : 1
Estimated Total Steel Weight (structural steel and access excludes purchased equipment)	300 tons	1000 tons
Estimated Total Steel Weight (plate steel -excludes purchased equipment)	500 tons	1400 tons

Work By Others:

- Receiving, unloading and storage of all equipment
- Erection labor, equipment and consumables
- Design and supply of foundations, anchor bolts and grouting
- Design and supply of any elevated concrete silos and decks including Q-deck and rebar
- Design and supply of ductwork and expansion joints
- Design and supply of I.D. Fan and related subsystems
- Design and supply of stack including stack platform and test ports
- Design and supply of ash removal system downstream of Seller's supplied surge bin outlet flanges and scrubber discharge flange
- Carbon Injection System, if required
- Design and supply of wire, conduit, junction boxes and all other erection materials related to electrical erection including cable, cable tray and/or conduit routing schedules or drawings
- Design and supply of light fixtures, convenience receptacles and welding receptacles
- Design and supply of plant communications ("Gaitronics" and similar) system, if any.
- Design and supply of lighting, receptacles, HVAC, and doors for enclosures, if required
- Design and supply of heat tracing, if required
- Design and supply of motor starters, MCC's, switchgear, power distribution panels, and other power distribution equipment such as medium or high voltage transformers
- Design and supply of equipment removal temporary hoists
- Heat insulation, lagging, flashing and any other accessories related to I&L erection
- Field touch-up and finish painting
- Elevators
- PLC's
- Design and supply of any DCS and/or field I/O racks and any communications interfacing hardware. This includes but is not limited to general DCS design, screen/graphics creation (except as noted above), programming, testing (including FAT) documentation.
- Design and supply of sub surface grounding system
- Demolition and/or hazardous material identification and abatement, if any
- Design and supply of fire detection/protection system and supply of emergency (UPS) power supply, if any
- Design and supply of continuous monitoring equipment including inlet and stack SO_2 Monitors
- Lightning protection, if any, and above grade equipment grounding to sub surface grid
- Performance testing
- Securing of all permits and licenses, including engineering activities required to secure same
- Creation of turnover packages, if any
- 3-D Models and 3-D CAD drawings, if any
- P.E. Stamps other than for support steel
- Spare parts, including start-up spares, (except for the quoted spare bags and cages and the spare water lance assemblies)
- Supplies and services which are not expressly mentioned in the scope of supplies and services

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SECTION 4

DESIGN and OPERATING DATA

Design Data:

The following "guarantee case" conditions were used for the design of each unit. All stated consumable type guarantees are at the below design cases. Note that emissions guarantees are valid for the entire specified range of inlet SO2 values.

Parameter	Units	Unit 1	Unit 2
Boiler Load	% MCR	100	100
Heat Input	MMBtu/hr	1160	2524
Scrubber Inlet Flow	Lb/hr	1,231,000	2,678,000
Scrubber Gas Flow	ACFM	398,000	866,000
Operating Inlet Temp.	°F	280	280
Scrubber Inlet Draft	In W.C.	-11.9"	-11.9"
Gas Composition			
N_2	%	75.54	75.54
O_2	%	4.92	4.92
CO_2	%	12.69	12.69
H_2O	%	6.52	6.52
SO_2	%	0.31	0.31
SO_3 [3]	#/hr	165	358
HF [3]	#/hr	4.1	8.8
HCl [1]	#/hr	15.9	35.3
NH_3 [1]	ppm	0	0
Particulate [2]	#/hr	9817	21,361

Notes: 1) Assumed value, or a calculated value based on assumed values
2) Calculated from specified fuel ash / HHV @ 90% carryover
3) Calculated at 2% SO_2 conversion by weight
4) Calculated from specified fuel F, assuming 0% removal in the boiler

Codes and Standards:

Allied has assumed the following other design conditions which were not specified.

Parameter	Units	Design
Excursion Temperature	Degrees F	400 for 30 minutes, excluding bags and cages
Design Pressure – Scrubber	Inches W.C.	+ 35" / -35"
Design Pressure – PJFF	Inches W.C.	+ 35" / - 40"
Site Elevation	Feet above Sea Level	971'
Barometric Pressure	Inches Hg	28.9
Ambient Temperature	Degrees F	Per ASHRAE
Wind Load	Code	IBC 2006
Snow Load	Code	IBC 2006
Seismic	Code	IBC 2006
Volumetric Lime Density (Hydrate / Pebble)	Lbs/Cu.Ft.	45 /65
Structural Lime Density	Lbs/Cu.Ft.	70
Volumetric Dust Density	Lbs/Cu.Ft.	45
Structural Dust Density	Lbs/Cu.Ft.	90

SECTION 5

PERFORMANCE AND GUARANTEES

The following performance and consumption guarantees given by the Seller with respect to Equipment furnished shall be valid on if (i) the Equipment is installed by Seller or is installed by others in accordance with Seller's specification; (ii) gas volumes and gas and dust characteristics are within the ranges stated in this proposal; and (iii) the Equipment has not been damaged by operation thereof by Buyer. The Seller's consumable type guarantees are based on the guarantee conditions as described in Section 4, above. Corrections to the stated consumable type guarantees for off-design operating conditions will be per the ALLIED supplied correction curves (supplied later).

Parameter	Units	Value	Notes	Test Method
SO_2 Emissions	Lb/MMBTU	0.142	1	EPA Method 6 or 6C
Particulate Emissions – dry front half	Lb/MMBTU	0.012		EPA Method 5
Opacity	%	Later, if required		EPA Method 9 or calibrated opacity monitor
HCl	%	Later, if required		EPA Method 26A
HF	%	Later, if required		EPA Method 26A
H_2SO_4	Lb/MMBTU	0.005	2	Controlled Condensate Method
Bag Life	Years from first fire	3		Material and Workmanship warranty

Notes:

1. Value represents 98% removal at the design inlet SO_2 value.
2. Please note that use of EPA Method 8 is not allowed as it is highly flawed.

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Operating Data – Guaranteed:

Parameter	Units	Unit 1	Unit 2
Pressure Drop [5]	Inch W.C.	16.5"	16.5"
Scrubber Water Consumption [1]	gpm	89	193
Hydrator Water Consumption [6]	gpm	19	42
Pebble Lime Consumption [2]	pph	15,525	33,685
Instrument Air [8]	scf	none	none
Power Consumption [3]	Kw-hr/hr	600	783

NOTES:

[1] Filtered for suspended particulate at 100 mesh. Temperature range from 40 to 120 Deg. F. maximum chloride level is 500 ppm.

[2] Lime consumption assumes CaO per the following:

- **Particle Size**: not greater than minus ¾" pebble. In addition the amount and size of fines needs to be defined by Owner prior to the design of the lime storage system.
- **Availability:** 90% minimum available CaO on a dry basis per ASTM C25.
- **Reactivity:** When using ASTM C110 slaking rate methodology:
  - "R 30 second" temperature rise at least 30 deg C.
  - "R 180 second" temperature rise at least 45 deg C.
  - "Total time" not greater than 300 seconds.

The guarantee value also assumes 100% hydrator conversion efficiency of CaO to $Ca(OH)_2$ and creation of hydrated lime with a BET surface area of at least 20 m^2/g. Once a lime sample is available for testing by Allied, Allied will perform a test run in a hydrator to assess actual hydrator performance. Adjustment to the above lime consumption values will be corrected at that time for actual hydrator performance. It is not possible to precisely predict hydrator performance without such a test.

[3] 24-Hour Average, based on a 92 Deg F ambient and excluding non process loads such as ventilation and space heaters but including hopper heat loads

[4] Not used

[5] The above pressure drop is the condition when the PJFF is operating with all compartments on-line, with on-line cleaning.

[6] Hydrator water shall be potable in quality and shall have a minimum temperature of 70 deg F.

[7] All of the above guarantees are assumed to be liquidatable at reasonable values. If any of the above are "make right" or have unusual LD values, Allied reserves the right to modify the guarantees

[8] Allied's scope includes provision of all required process air (service air, if any, by others).

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WARRANTY

ALLIED warrants that all good furnished under any Purchase Order issues shall be free from defects in material and workmanship within twelve (12) months from the date the equipment is first placed in operation or within thirty (36) months from delivery of the equipment, whichever is earlier.

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SECTION 6

PRICING

Base Bid:

ALLIED's current day budgetary, lump sum price, for the scope identified in this proposal is:

Unit 1 - $ 16,700,000

Unit 2 - $ 27,400,000

Optional Pricing:

1. Erection: ALLIED's current day budgetary, lump sum price for the mechanical, electrical, and I&L erection scope (civil and concrete silos by others) is $17,600,000 for Unit 1 and $28,800,000 for Unit 2. This assumes non-union labor and reasonable site conditions. Price includes Allied's erection advisor(s) and field service personnel.

Pricing Notes:

- Pricing is based on cash neutral Payment Terms, that assumes invoices for major buyout items upon placement of PO's with our sub-vendors
- Pricing is escalatable.
- Price assumes "typical" commercial risk. Allied reserves the right to modify this offering for price and schedule once the commercial specifications are received and reviewed. Price assumes mutually agreed upon terms and conditions
- Price is budgetary and not valid for acceptance.
- Price does not include sureties of any kind (10% retention is assumed, however)

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TYPICAL SCHEDULE

ALLIED Typical "High Level" Deliverables for each plant:

General Arrangement Drawing	30 days ARO
Process Flow Diagram	30 days ARO
N.T.E. Load Diagram	45 days ARO
Preliminary P&ID's	60 days ARO
Preliminary One Line Diagram	60 days ARO
Start Material Delivery	14 months ARO
End Material Delivery	24 months ARO

Circulating Fluid Bed (CFB) Scrubber
Reference List

ALLIED ENVIRONMENTAL SOLUTIONS, INC.

	Client Location Country	Application	Pre-Collector	Downstream Particulate Control	Gas Volume	Gas Temperature	SO_2	HCl	Particulate	Reagent	Year Ordered	Start-up
	* ash recirculation enters absorber under the venturis			(new)		Inlet	Inlet Outlet % Removal	Inlet Outlet % Removal	Outlet			
					ACFM	° F	PPM		Gr/ACF			
1	VAW Bonn Toeging Germany	Aluminum Potline	ESP	ESP	2 x 248,000	230			0.009	Al_2O_3	Dec 78	Jun-80
2	VAW Bonn Norf Germany	Aluminum Potline	ESP	ESP	8 x 248,000	230			0.009	Al_2O_3	Dec 80	Apr-82
3	VAW Bonn Schwandorf Germany	Municipal Waste	-	ESP	3 x 111,500	500	175 70 60	950 47 95	0.016	$Ca(OH)_2$	Dec 80	Sep-82
4	Bayernwerk München Schwandorf Germany	Coal-fired Boiler	-	ESP	1 x 231,500	330	1,500 70 95		0.04	$Ca(OH)_2$	Dec 83	Nov-84
5	KW Borken Preussenelektra Hannover Germany	Coal-fired Boiler	-	ESP	1 x 585,500	330	4,550 140 97		0.02	$Ca(OH)_2$	Mar 85	Dec 87
6	KW Siersdorf EBV Herzogenrath Germany	Coal-fired Boiler	ESP	ESP	2 x 315,400	266	945 70 93		0.015	CaO / $Ca(OH)_2$	Mar 86	May 88

Circulating Fluid Bed (CFB) Scrubber Reference List

ALLIED ENVIRONMENTAL SOLUTIONS, INC.

	Client Location Country	Application	Pre-Collector	Downstream Particulate Control	Gas Volume	Gas Temperature	SO_2	HCl	Particulate	Reagent	Year Ordered	Start-up
	* ash recirculation enters absorber under the venturis			(new)		Inlet	Inlet Outlet % Removal	Inlet Outlet % Removal	Outlet			
					ACFM	° F	PPM		Gr/ACF			
7	Buendner Cementwerke Untervaz Switzerland	Cement	-	ESP	1 x 217,500	240	1,260 140 89		0.015	$CaCO_3$ $Ca(OH)_2$	Jul-86	Apr-88
8	Adam Opel AG Rüsselsheim Germany	Coal-fired Boiler	ESP	ESP	1 x 164,200	300	945 70 92	100 12 88	0.009	$Ca(OH)_2$	Aug-88	Mar 90
9	ÖDK Klagenfurt Zeltweg Austria	Coal-fired Boiler	ESP	ESP	1 x 547,200	300	840 70 92		0.015	CaO / $Ca(OH)_2$	Mar 91	Jan-93
10	ÖDK Klagenfurt St. Andrä Austria	Coal-fired Boiler	-	Fabric Filter	1 x 410,000	300	840 70 92		0.009	$CaCO_3$ $Ca(OH)_2$	Mar 93	Aug-94
11	Black Hills Power & Light Gillette, Wyoming USA	Coal-fired Boiler	-	ESP	1 x 440,000	290	560 12 98		0.0036	CaO / $Ca(OH)_2$	Feb-93	Apr-95
12	Roanoke Valley Energy F. Weldon, North Carolina USA	Coal-fired Boiler	-	Fabric Filter	1 x 170,000	310	1,200 80 93		0.0036	$Ca(OH)_2$	Dec 92	Feb-95

Circulating Fluid Bed (CFB) Scrubber
Reference List

ALLIED ENVIRONMENTAL SOLUTIONS, INC.

	Client *Location* Country	Application	Pre-Collector	Downstream Particulate Control	Gas *Volume*	Gas Temperature	SO_2	HCl	Particulate	Reagent	Year Ordered	Start-up
	* ash recirculation enters absorber under the venturis			(new)		Inlet	Inlet Outlet % Removal	Inlet Outlet % Removal	Outlet			
					ACFM	° F	PPM		Gr/ACF			
13*	Plzenska Teplerenska *Pilzen* Czech Republic	Coal-fired Boiler	ESP	ESP	1 x 701,500	390	1,820 520 71	40 <1 98	0.015	CaO / $Ca(OH)_2$	Oct 95	Sep-97
14*	Stadtwerke Frankfurt/Oder Germany	Coal-fired Boiler	-	Fabric Filter	1 x 104,900	300	685 86 87	20 6 70	0.006	$Ca(OH)_2$	Nov-95	Aug-97
15*	Setuza a.s. Usti n. L. Czech Republic	Coal-fired Boiler	ESP / Fabric Filter	Fabric Filter	1 x 258,300	285	1,022 70 93	20 3 85	0.015	$Ca(OH)_2$	Jun-97	Sep-98
16	AES Guayama Puerto Rico	Coal-fired CFB Boiler	-	ESP	2 x 911,600	280	146 8 95	161 7 96	0.02	Ash from CFB-Boiler (CaO)	Dec-99	May-02
17*	Treibacher Industries AG Treibach Austria	Metalurgical Rotary Kiln	Fabric Filter	Fabric Filter	1 x 40,400	428	4,900 14 99.7	63 < 1 99	0.01	Ca(OH)2	Aug-01	Nov-02
18*	Electricity Supply Board *Lanesborough* Ireland	Peat / CFB-Boiler	-	Fabric Filter	1 x 386,500	320	1,050 70 93.3	47 3 93	0.01	Ash from CFB-Boiler (CaO)	Aug-02	Jun-04

Circulating Fluid Bed (CFB) Scrubber
Reference List

ALLIED ENVIRONMENTAL SOLUTIONS, INC.

	Client Location Country	Application	Pre-Collector	Downstream Particulate Control	Gas Volume	Gas Temperature	SO_2	HCl	Particulate	Reagent	Year Ordered	Start-up
	* ash recirculation enters absorber under the venturis			(new)		Inlet	Inlet Outlet % Removal	Inlet Outlet % Removal	Outlet			
					ACFM	° F	PPM		Gr/ACF			
19*	Electricity Supply Board Shannonbridge Ireland	Peat / CFB-Boiler	-	Fabric Filter	1 x 571,300	320	2,450 70 97.1	47 3 93	0.01	Ash from CFB-Boiler (CaO)	Aug-02	Sep-04
20*	Urbanaenergia Cantabria Spain	Municipal Waste / Roller Grate	-	Fabric Filter	1 x 92,600	410	280 17.5 93.8	1,009 6 99.4	0.003	$Ca(OH)_2$	Dec-02	Sep-04
21*	Shanxi Yushe Power Plant Yushe /Shanxi China	Coal-fired Boiler	ESP (1 Chamber)	ESP	2 x 945,600	248	1,206 121 90		0.03	CaO / $Ca(OH)_2$	Mar-03	Jul-04 Oct-04
22*	Huaran Electric Group Diaozuo Huafu China	Coal-fired Boiler	ESP	ESP	2 x 426,000	265	245 25 90		0.015	CaO / $Ca(OH)_2$		2005 / 2006
23*	Luneng Group Liaocheng China	Coal-fired Boiler	-		2 x 1,082,000	257	2295 173 92.5		0.015	CaO / $Ca(OH)_2$		2005 / 2006
24*	Huatei Group Huatei/Shandong China	Coal-fired Boiler	ESP	ESP	1 x 442,000	285	1146 88 92.3		0.015	CaO / $Ca(OH)_2$		Jan-06

Circulating Fluid Bed (CFB) Scrubber Reference List

ALLIED ENVIRONMENTAL SOLUTIONS, INC.

	Client Location Country	Application	Pre-Collector	Downstream Particulate Control	Gas Volume	Gas Temperature	SO_2	HCl	Particulate	Reagent	Year Ordered	Start-up
	* ash recirculation enters absorber under the venturis			(new)		Inlet	Inlet Outlet % Removal	Inlet Outlet % Removal	Outlet			
					ACFM	° F	PPM		Gr/ACF			
25*	State Grid Corporation of China Matou/Hebei China	Coal-fired Boiler	ESP	ESP	1 x 860,000	320	885 77 91.3		0.022	CaO / $Ca(OH)_2$		Jun-06
26*	China Petroleum & Chemical Corp Guangzoz/Guangdpng China	Pet Coke	ESP	Fabric Filter	2 x 432,000	298	431 43 90		0.015	CaO / $Ca(OH)_2$		Aug-06
27*	China Petroleum & Chemical Corp Luanhel/Hebei China	Coal-fired Boiler	ESP	Fabric Filter	2 x 454,000	284	1120 87 92.2		0.015	CaO / $Ca(OH)_2$		Oct-06
28*	Georgia Pacific Port Hudson, Louisianna USA	Pet Coke & Coal CFB Boiler	-	ESP	1x 440,000	300	286 26 90	90	0.006	Ash from CFB-Boiler (CaO)	Mar-05	Feb-07
29*	Electricity Supply Board Moneypoint Ireland	Coal-fired Boiler	ESP	Fabric Filter	3 x 1,120,000	320	1,470 120 91.6		0.01	CaO / $Ca(OH)_2$		2007 2008 2009
30*	CLECO Lena, Louisianna USA	Pet Coke & Coal CFB Boiler	-	Fabric Filter	2 x 935,000	280	340 60 82		0.004	Ash from CFB-Boiler (CaO)	Feb-06	Spring 2009

Circulating Fluid Bed (CFB) Scrubber
Reference List

	Client Location Country	Application	Pre-Collector	Downstream Particulate Control	Gas Volume	Gas Temperature	SO_2	HCl	Particulate	Reagent	Year Ordered	Start-up
	* ash recirculation enters absorber under the venturis			(new)		Inlet	Inlet Outlet % Removal	Inlet Outlet % Removal	Outlet			
					ACFM	° F	PPM		Gr/ACF			
31*	Texas Utilities Milam County, Texas USA	Lignite CFB Boiler	-	Fabric Filter	2 x 1,045,000	280	86 30 65	50 0.16 99.7	0.0055	Ash from CFB-Boiler (CaO)	Jul-06	Summer 2008
32*	CGTEE Candiota Brazil	Coal-fired Boiler	ESP	ESP	1 x 1,200,000	284	2,673 381 85		0.07	CaO / $Ca(OH)_2$		Fall 2009
33*	City Utilities of Springfield Springfield, Missouri USA	Coal-fired Boiler	-	Fabric Filter	1 x 983,000	302	390 33 91.5	5.5 0.5 91	0.0051	$Ca(OH)_2$	Apr-07	Fall 2010
34*	PPGA, Whelan Energy Hastings, Nebraska USA	Coal-fired Boiler	ESP	Fabric Filter	1 x 874,000	285	524 34 93.5	10 0.7 93	0.0031	CaO / $Ca(OH)_2$	Jun-07	Fall 2010
35*	Dominion Energy Virginia City Hybrid Energy Center Virginia City, Virginia USA	Waste Coal & Biomass CFB Boiler	ESP	Fabric Filter	2 x 1,046,000	279	169 47 69	134 6.6 96.3	0.0037	Ash from CFB-Boiler (CaO)	Jan-08	Spring 2011
36*	Entergy Little Gypsy Montz, LA USA	Pet Coke & Coal CFB Boiler	-	Fabric Filter	2 x 904,000	277	373 60 82.3		0.0041	Ash from CFB-Boiler (CaO)	Mar-08	Summer 2011

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1.0 Budgetary Pricing – BPEI Response

BPEI has developed budgetary pricing in accordance with Burns & McDonnell (BMcD) e-mail specification for these East Kentucky Power (EKP), Cooper Station, Turbosorp (DFGD) systems, and also in accordance with the scope of supply descriptions contained within the proposal documentation provided. As described within those documents, all systems have been considered as dedicated by unit, with minimal common (shared) equipment assumed at this time.

Budgetary Pricing	Cooper Unit 1	Cooper Unit 2
Turbosorp Systems	Included	Included
PJFF Systems	Included	Included
Reagent Prep Systems	Included	Included
Solids Handling Systems	Included	Included
Balance of Equipment Supply	Included	Included
Shipping & Freight	Included	Included
Checkout, Start-up, Training	Included	Included
Subtotal Equipment Supply	**$18,000,000**	**$31,500,000**
(Option) Erection & Installation	$16,500,000	$23,500,000

Pricing as presented above is reflective of current costs, and does not include potential escalation of materials and/or labor going forward. Our estimates however are supported by recent and ongoing procurements of similar materials and process equipment, and we have assumed project execution will initiate in early 2009.

As to projecting erection craft manhours and specific subcontractor selections, BPEI can and will provide this information, if required and applicable, as part of a firm proposal in response to a formal RFP with detailed scope of supply and site specific requirements. Lacking those detailed requirements, we must decline to do so at this time, for this preliminary and budgetary effort.

We can however offer to provide preliminary and budgetary only overall construction costs, based upon our experience with the several Turbosorp systems already installed or in process. Based upon that experience, the erection and installation portion of those projects, that are similar to the projects being discussed here for Cooper Station, has typically been 40% to 50% of the overall project cost. Therefore, the construction pricing provided to BMcD for this effort is simply factored based upon that experience as well, and no detailed estimates have been performed at this time. The actual construction cost is of course subject to the final scope of supply, the specific site conditions encountered, the final schedule requirements, and the customer's specific commercial requirements, as well as other, potential issues.

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502233 Turbosorp® Scope of Supply 10/17/08

Note: The purpose of this document is to provide BMcD with a defined Scope of Supply for the Turbosorp® systems required for East Kentucky Power Cooper Station, Units 1 and 2, and reflective of the budgetary pricing provided by BPEI October 17, 2008.

Two (2) separate Turbosorp® systems are provided by BPEI, one (1) dedicated to Cooper Station Unit 1, and one (1) dedicated to Cooper Station Unit 2. The baghouse systems and the reagent prep systems to be provided are also separate and dedicated to the respective Turbosorp® systems, with the exceptions noted immediately below.

The equipment common to both (Unit 1 & 2) Turbosorp® systems is the following:

- A single pebble lime silo with 7 days storage capacity (silo & auxiliaries by others)
- One (1) process water tank sized for one hour storage (provided by BPEI)
- One (1) water injection system including two (2) high pressure water pumps and one (1) common spare pump (provided by BPEI)

The equipment included by BPEI within each Turbosorp®/Baghouse/Reagent System:

- Pebble lime transport systems from the storage silo to the hydration systems
- Lime hydration systems, consisting of 2 @ 100% trains, and including redundant day bins, hammer mills, other hydration equipment, and a hydrated lime storage tank with 24 hours capacity
- Flue gas inlet duct including expansion joints, within battery limits
- One (1) hydrated lime injection system including redundant blowers
- One (1) Turbosorp CDS reactor
- One (1) Pulse Jet Fabric Filter (PJFF) system with One (1) PJFF bag cleaning system
- Two (2) air slides with dosage valves for product recycle
- One (1) Turbosorp® reactor bottom product removal system
- Two (2) product removal systems including surge bins
- Flue gas outlet duct including expansion joints, within battery limits,
- Flue gas recirculation ducts and dampers including expansion joints.
- Structural steel for support and access to equipment provided

Equipment, systems, and supplies assumed to be provided by others:

- Booster Fans and/or ID Fans
- Pebble lime storage
- Product (ash) transport from the surge bins to the product silo
- Product conditioning facility (if required) including truck unloading stations,
- Air compressors for service and instrument air
- MCC and power distribution,
- Ductwork beyond battery limits
- Utilities and consumables
- Facility modifications, foundations, & construction

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Proposal No.	Plant and Unit No.	Document No.
502233	Eastern Kentucky Power Cooper Units 1 & 2	502233-120401101-00

Document

SYSTEM DESCRIPTION
Turbosorp Circulating Dry Scrubber (CDS)

Note:

ISSUE FOR INFORMATION

1st Issue	Name	Date	Phone No.	Signature
Written by	Sarah Balassy	02.Oct.08	704.526.2129	
Reviewed by	Terence Ake	02-Oct-08	704.717.2408	
Approved by				

Rev.	Date	Item	Changed by	Approved by

Distribution List:	No. Pages
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1. Introduction

Babcock Power Environmental (BPEI) is supplying to Eastern Kentucky Power two (2) Turbosorp Circulating Dry Scrubbers (CDS) for the Cooper Power Station in Somerset, Kentucky: one for the Unit 1 boiler and the other for the Unit 2 boiler. The Turbosorp CDS removes sulfur dioxide (SO_2), sulfur trioxide (SO_3), hydrochloric acid (HCl), other acid gases, and particulate from the boiler flue gas for the units. This document describes the arrangement of the system components and the BPEI scope of supply for the Eastern Kentucky Power Cooper Units 1 & 2 Turbosorp CDS systems. The Process Description, document 502233-120401100, describes how the Turbosorp CDS works to remove high percentages of the acid gases and particulate from the boiler flue gas.

2. System Description

The Turbosorp CDS for Cooper Unit 1 and Unit 2 are shown as process flow diagrams in drawings 502233-123000101 and 502233-123000102. They are assumed to be downstream of existing Induced Draft (ID) fans for Units 1 & 2. (The Turbosorp CDS can also operate upstream of the ID fans if it provides a better arrangement for the power station). The predominant material of construction for all major process (flue gas conveying) components is mild steel.

The Turbosorp CDS includes a cylindrical reactor vessel integrated with a pulse jet fabric filter, air slides for product recycle, hydrated lime injection, water injection, and induced draft booster fans. The booster fans are downstream of the pulse jet fabric filter, and they overcome the increased flue gas pressure drop due to the CDS. The Turbosorp CDS includes a flue gas recirculation damper that opens at low loads. While they operate, the Turbosorp CDS systems discharge clean boiler flue gas to the stacks for Units 1 & 2.

The Turbosorp CDS removes SO_2 and other acid gases in the flue gas by reacting the acid gases with dry, solid hydrated lime. The hydrated lime for the Turbosorp CDS is produced from quick lime delivered to the site using quick lime hydrators or local suppliers deliver it fresh to the site. The quick lime unloading, storage, and transport facility serves both the Unit 1 and Unit 2 Turbosorp CDS systems. When making hydrated lime on site, the quick lime is unloaded from a truck or railcar and stored in a large silo in the quick lime unloading, storage, and transport facility. A separate quick lime hydration facility converts the quick lime to hydrated lime with quick lime hydrators. Redundant transport blowers pneumatically transport the quick lime as it feeds out of the silo to fill the quick lime day bins in the quick lime hydration facility. If the quick lime is a pebble lime over 3/8" (9 mm), then the pebble lime is crushed to be a suitable size for the quick lime hydrator as it feeds out of the silo.

The quick lime hydration facility includes two quick lime hydrators that serve both units. Each is sized to treat the design coal for both of the units at the Cooper Station. It is possible to operate both quick lime hydrators to fill the hydrated lime day bins faster than when operating one quick lime hydrator. While a quick lime hydrator operates, a screw feeder feeds the quick lime at a controlled rate from the day bin to the quick lime hydrator. The quick lime hydrator converts quick lime to hydrated lime by adding water while maintaining the water to quick lime mass ratio. As it is being made, the hydrated lime transports from the operating quick lime hydrator to fill either the Unit 1 or the Unit 2 hydrated lime day bin. When operating both quick lime hydrators, the quick lime can be transported to one day bin, or one quick lime hydrator can transport hydrate to one day bin, and the other quick lime hydrator can transport hydrate to the other day bin. The hydrated lime transport blowers include one common spare blower.

At each Turbosorp CDS, the hydrated lime pneumatically injects from the hydrated lime day bin to the Turbosorp reactor according to the CDS SO_2 removal setpoint. Each Turbosorp CDS includes its own hydrated lime day bin, and it includes a truck unloading station for loading fresh hydrated lime. There is one hydrated lime injection blower and one spare blower for each Turbosorp CDS.

The Turbosorp CDS removes 98% of the SO_2 and the acid gases from the flue gas. The Turbosorp reactor achieves these high removal percentages because the flue gas contacts with a fluidized bed of product recycle from the reaction of hydrated lime with SO_2. As the product leaves the reactor, the pulse jet fabric filter removes it from the flue gas, and air slides recycle it back to the reactor at a high rate. The reactor pressure drop sets the product recycle rate to maintain the fluidized bed. The pulse jet fabric filter acts as a final particulate removal device for the Turbosorp CDS removing product to keep particulate below stack emission limits. The flue gas recirculation damper opens at less than 65% load to provide enough flue gas velocity to keep a fluidized bed in the reactor.

Water injected in the reactor reduces the temperature of the flue gas to the best temperature for removing the acid gases in the reactor. It wets the hydrated lime particles exposing more surface area to react with SO_2. However, if the reactor temperature decreases too close to the adiabatic saturation temperature of the flue gas, then the product becomes sticky and lumpy, and it will fall out of suspension in the reactor. The difference between the reactor temperature and the adiabatic saturation temperature is the approach temperature. The water injection system maintains the water injection rate to keep the reactor outlet temperature at an approach temperature that provides the lowest hydrated lime consumption without operating problems with the product.

The water injection system for Unit 1 and Unit 2 each includes a primary pump for each unit and one common spare pump. One common process water tank supplies water to the high-pressure pumps, and the pumps supply water to the water injection lances in the reactor for each unit. Each water injection lance includes a spill back nozzles that recycle the most of the water back to the process water tank. The spill back nozzle provides a fine spray of water droplets in the reactor.

The reaction of SO_2 and hydrated lime produces a solid product mainly of calcium sulfate and calcium sulfite. The product removal system removes the product from the air slides to maintain the air slide levels. The product discharges to a surge bin for each air slide. As the product discharges from the surge bins, it is pneumatically transported to the product silo with redundant transport blowers. There is assumed to be one common product storage facility for the Cooper

Units 1 & 2 Turbosorp CDS systems. In the product storage facility, the product ash is conditioned before it is loaded onto trucks for disposal.

The Turbosorp CDS removes most of the gaseous mercury (Hg) from the boiler flue gas. An activated carbon system is an option to enhance mercury removal by the Turbosorp CDS. The activated carbon system serves both Unit 1 & Unit 2. It includes an activated carbon unloading station, silo, and injection system to inject activated carbon in the inlet flue gas duct. The injection system includes two blowers to inject activated carbon for each unit and one common spare blower.

3. Scope of Supply

BPEI is supplying two (2) Turbosorp Circulating Dry Scrubbers at the Eastern Kentucky Cooper Power Station. One will be installed downstream of the owner's ID fans for Cooper Unit 1 and the other downstream of the owner's Cooper Unit 2 ID fans. Each will discharge clean flue gas to the owner's stack for each unit.

BPEI supplies the following components common to Unit 1 & Unit 2:

- One (1) quick lime truck unloading, storage and transport system,
- One (1) quick lime hydration system including two (2) quick lime hydrators each with capacity for both Unit 1 and Unit 2,
- One (1) process water tank sized for one hour storage for both Unit 1 & Unit 2,
- One (1) water injection system including two (2) high pressure water pumps and one (1) common spare pump,
- One (1) optional activated carbon system with two (2) injection blowers and one (1) common spare blower.

BPEI supplies the following components for Unit 1 & Unit 2:

- Flue gas ductwork to the Turbosorp CDS including expansion joints, within battery limits,
- One (1) hydrated lime day bin,
- One (1) hydrated lime injection system with one (1) injection blower and one (1) spare blower,
- One (1) Turbosorp CDS reactor,
- One (1) Pulse Jet Fabric Filter (PJFF) system,
- One (1) PJFF bag cleaning system,
- Two (2) air slides with dosage valves for product recycle,
- One (1) Turbosorp reactor bottom product removal system to transport product to the product silo,
- Two (2) product removal systems including surge bins and a transport system to transport product from each air slide to the product silo,
- Flue gas outlet ductwork including expansion joints, within battery limits,
- Flue gas recirculation duct and damper including expansion joints,
- Two (2) booster fans.

A party other than BPEI generally supplies the following components, but any of these can be supplied by BPEI as well:

- Product storage silo facility,
- Product conditioning facility including truck unloading stations,
- Air compressors for service and instrument air.
- MCC and power distribution,
- Ductwork beyond battery limits.

BabcockPower
ENVIRONMENTAL

Proposal No.	Power Station and Unit No.	Document No.
502233	Eastern KY Power Cooper Station Units 1 & 2	502233-120401100-00

Document

PROCESS DESCRIPTION
Turbosorp Circulating Dry Scrubber (CDS)

Note:

ISSUE FOR INFORMATION

1st Issue	Name	Date	Phone No.	Signature
Written by	Terence Ake	01-Oct-08	704-717-2408	
Reviewed by				
Approved by				

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1. INTRODUCTION

The Turbosorp® Circulating Dry Scrubber (CDS) can be installed either downstream or upstream of the I.D. fans of a boiler. Booster fans overcome the added pressure drop from the CDS. The Turbosorp CDS process is described in this document.

1.1 CDS Process Description

The Turbosorp CDS removes the acidic constituents of the flue gas (primarily SO_2 SO_3, HCl, and HF) by reaction the acid gases with hydrated lime. The system includes the CDS reactor vessel, hydrated lime injection, water injection, product ash recycle and flue gas recirculation for operating at low loads. The solid products exiting the CDS vessel (flyash, unreacted lime, and reaction products $CaSO_3$, $CaSO_4$, $CaCO_3$, $CaCl_2$ and CaF_2) are separated from the flue gas in the pulse jet fabric filter system and recycled to the vessel inlet at a high rate. The recycled product ash flow establishes a fluidized bed in the CDS reactor. The fluidized bed provides a high contact time of the solids with the flue gas to minimize the amount of hydrated lime used in the system.

The CDS reactions are as follows:

$$Ca(OH)_2 + SO_2 \leftrightarrow CaSO_3 \bullet ½H_2O + ½H_2O \quad (1)$$
$$Ca(OH)_2 + SO_3 \leftrightarrow CaSO_4 \bullet ½H_2O + ½H_2O \quad (2)$$
$$CaSO_3 \bullet ½H_2O + ½O_2 \leftrightarrow CaSO_4 \bullet ½H_2O \quad (3)$$
$$Ca(OH)_2 + CO_2 \leftrightarrow CaCO_3 + H_2O \quad (4)$$
$$Ca(OH)_2 + 2HCl \leftrightarrow CaCl_2 + 2H_2O \quad (5)$$
$$Ca(OH)_2 + 2HF \leftrightarrow CaF_2 + 2H_2O \quad (6)$$

The CDS also partially removes mercury. Powdered Activated Carbon (PAC) injected into the duct upstream of the Turbosorp reactor enhances mercury removal by the system.

Figure 1 is an overview of the Turbosorp CDS process. At the inlet of the CDS reactor vessel, flue gas passes through a horizontal duct and a 90° turn in the gas path. At this bend a flyash hopper collects any ash that may fall out. Once flowing in the vertical direction the flue gas passes through a group of venturi nozzles. The venturi nozzles accelerate the flue gas just prior to the injection of high-pressure water, recycled solids, and hydrated lime. The reactor acts as a fluidized bed, assuring maximum contact between the pollutants in the flue gas and the hydrated lime. The reactor is characterized by high turbulences and optimal chemical and physical heat and mass transfer rates. Water is added to bring the flue gas closer to the saturation temperature where the SO_2 absorption is most effective. The high dust load leaving the reactor is removed in the pulse jet fabric filter, bringing the flue gas particulate to the required particulate emission values.

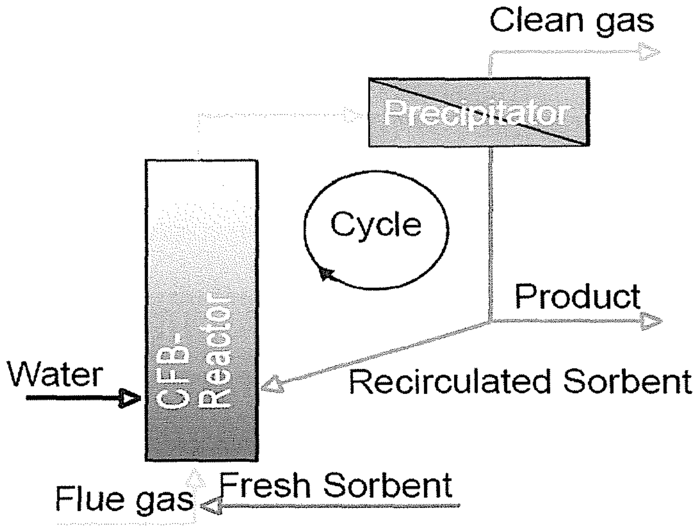


Figure 1. Turbosorp®/CDS Process Overview

SO_2 is measured at the inlet and outlet of the CDS reactor. From these measurements, the SO_2 removal efficiency and SO_2 loading is computed and varies the quantity of hydrated lime injected into the reactor.

The final residue of the CDS process is a dry product, which may be landfilled or used in the cement industries for non-structural components. Alternately, it can also be stabilized and used for filling purposes in coalmines or as a concrete-like filling material for road construction.

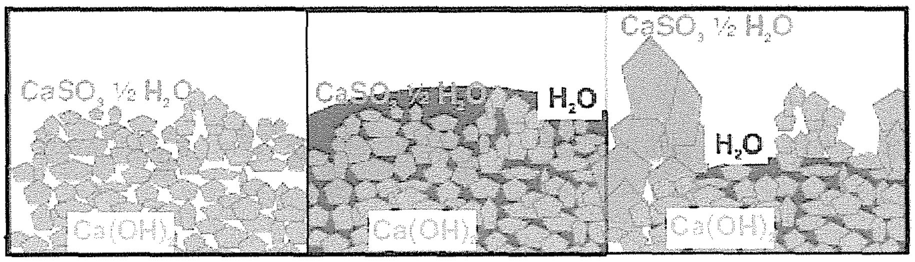
1.2 Sorbent Preparation and Injection

Hydrated lime, $Ca(OH)_2$, is the sorbent used in the CDS process. It can be either delivered to the power station or made on site. If it is made on site, quick lime (CaO) is delivered to the site by truck or rail and subsequently hydrated before it is injected in the CDS. A storage silo in the railcar unloading facility receives and stores the delivered quick lime. If the quick lime is greater than 3/8" [9 mm], then a crusher can be included to crush the quick lime. The crushed quick lime is pneumatically conveyed from the silo to either of two (2) 100% quick lime hydration trains near the Turbosorp reactor. Each lime hydration train includes a quick lime day bin, weighing screw feeders, water pumps, hydrator reactor, and pneumatic conveying equipment. The weigh screw feeders control the rate of quick lime to the three-stage hydrator reactor. Within the hydrator, the quick lime is mixed with water and agitated until the hydration reaction is complete. Lime hydration is an exothermic reaction that yields excess water. The excess water is vented to the quick lime hydrator baghouse with a small amount of hydrated lime dust. The fine hydrated lime is pneumatically conveyed from the hydrator to the hydrated lime day bin for the Turbosorp reactor

Based on CDS chemistry demand, a speed-controlled rotary vane feeder controls the flow of hydrated lime from the hydrated lime silo to the CDS reactor as it is pneumatically conveyed by two (2) transfer air blowers. The hydrated lime control loop controls the SO_2 flue gas concentration at the outlet of the CDS. The dosing loop is a feed forward PID controller, which calculates the hydrated lime demand of the reactor based on the difference between the inlet and outlet SO_2 flue gas concentrations and the flue gas flow rate.

1.3 Water Injection

The injection of water and subsequent cooling of the flue gas mainly serve to set optimum operating conditions for the reaction of the acid gas pollutants with the basic lime sorbent particles. In addition to the temperature reduction of the flue gas, the addition of water leads to an increase in the relative humidity of the flue gas. Furthermore, the wetting of the recirculated sorbent in the reactor creates new and reactive surfaces accessible in the solid particles as product layers. When formed, the layers again become detached by this wetting. Refer to Figure 2 for a schematic of the mechanism.



Reaction after first pass | Water added to surface during recirculation | Sulfite crystal forms, exposing fresh surfaces

Figure 2. Mechanism for the Reactivation of Recirculated Sorbent

Water lance(s) inject water into the Turbosorp reactor. There is also one (1) spare lance to quickly replace an operating lance. Each lance includes a high-pressure spill-back nozzle that atomizes the water into fine drops. Two (2) 100% high-pressure pumps increase the pressure of the water supply to the lances to 500 psig. The water flow control loop controls the reactor outlet flue gas temperature. It opens and closes the process water control valve in the recirculation piping from the water nozzle to the water tank to increase flow to the water injection lances. To adjust the controller response, the reactor outlet temperature process variable is adjusted for a factor of the change in the flue gas flow rate and inlet temperature.

A process water tank is equipped with a continuous filling level measurement system and minimum and maximum level alarms, supples water for the Turbosorp water injection system. When the tank water level falls below a minimum set value, the power station water supply valve opens to fill the tank until it reaches maximum level.

1.4 Ash Recycle

A large flow of product and unreacted lime collected by the baghouse is recycled back into the CDS by two (2) 50% ash conveying air slides. Each air slide consists of a sloped piece of ductwork with a thick fabric material dividing the top portion of the duct from the lower half. Redundant blowers provide air along the lower half of this air slide that fluidizes the solids and permits the flow of solids by gravity to the reactor vessel. The product recycle control loop controls the flow of product to maintain a reactor pressure drop setpoint. Another control loop biases the flow through each air slide to keep the product levels in each air slide the same.

1.5 Ash Removal

The product generated from the CDS is removed from the air slides by a product removal control loop that keeps the air slide levels below a maximum setpoint. Each air slide includes a product removal train that includes a variable speed rotary feeder, surge bin, and pneumatic transport to a common product silo.

1.6 Flue Gas Recirculation

To maintain a fluidized bed in the Turbosorp reactor at low loads, a portion of the flue gas stream downstream of the booster fans recirculates to the inlet duct of the CDS. A single flue gas recirculation damper modulates the flue gas recirculation rate according to a control loop to keep the baghouse outlet flue gas flow above a minimum setpoint.

1.7 Particulate Removal – Pulse Jet Fabric Filter (PJFF)

As part of the Turbosorp CDS, a single (1) Low Pressure Pulse Jet Fabric Filter system removes particulate from the flue gas. The fabric filter system removes the large flow of recirculated product from the Turbosorp reactor leaving the flue gas with a particulate emission at or below the required emission at the stack. The particulate forms a layer on the outside of the filter bags that both aids in filtration and enhances SO_2 removal.

The fabric filter system includes a baghouse with a number of compartments of filter bags and a bag cleaning air system. As the flue gas flows through the baghouse, particulate is stripped from the flue gas and collected in the baghouse hoppers. The hoppers include startup heaters and vibrators to enhance product flow from the baghouse hoppers to the air slides.

The filter bags are periodically cleaned with air. The frequency of the cleaning pulse is adjusted as a function of flue gas pressure drop across the baghouse. Three (3) 50% blowers (two (2) operating and one (1) spare) supply compressed, dried air for filter bag cleaning.

Each baghouse compartment also includes inlet and outlet dampers. The compartment dampers isolate a compartment for maintenance. The baghouse may include bypass dampers that are closed during normal operation. At boiler startup or severe upset conditions, the baghouse may be bypassed by closing the inlet and outlet dampers on all compartments and opening the bypass dampers to protect the bags.

2. Booster Fans

Two (2) 50% booster fans serve two functions for the Turbosorp CDS:

- They provide the motive force needed to overcome the additional pressure drop imposed on the flue gas path by the Turbosorp CDS.
- They allow the CDS to operate at reduced Unit loads by recycling a portion of flue gas from the booster fan outlet to the CDS vessel inlet, thereby keeping the solids bed in the vessel fluidized.

The discharges of the booster fans tie into the ductwork upstream of the stack.

3. Air Compressors

The Turbosorp CDS instrument air can be supplied by a new compressed air system if the power station instrument air supply is not sufficient or cannot be used. The Turbosorp CDS instrument air system consists of two (2) 100% air compressors, one (1) 100% air receiver, one (1) 100% dryer, and associated accessories including filters, drains, and valves. Each oil-free type air compressor provides air at 100 psig and sufficient air flow for the Turbosorp CDS.

October 22, 2008

East Kentucky Power
Cooper Station, Units 1 and 2
Selective Catalytic Reduction Systems
BASIS OF ESTIMATE

B&W has used the information in the table below as the basis for development of a current day order-of-magnitude estimate for the design, and fabrication/procurement of a Selective Catalytic Reduction system at Cooper Station, Units 1 & 2:

Design Parameter (Please verify)	**Cooper 1**	**Cooper 2**
Generating Capacity	115 MW	249 MW
Fuel	Bituminous coal	Bituminous coal
Gas Temp (Full Load)	670°F	670°F
Gas Flow (Full Load)	1105 klb/hr	2088 klb/hr
Inlet NOx	0.30 lb/mkb	0.28 lb/mkb
NOx at Stack	0.07 lb/mkb	0.07 lb/mkb
NOx Removal Efficiency	%	%
Reagent Type	Aqueous ammonia	Aqueous ammonia
Ammonia Storage Capacity	na	na
Ammonia Slip	2 ppm	2 ppm
Arrangement/Construction Difficulty	+/- Average (4)	+/- Average (4)
Outage Duration	TBD	TBD
Non-outage Erection	Significant	Significant
Contract Award to Operation	30 months	30 months

Each estimated system includes an SCR reactor with catalyst and associated fluework upstream of the AIG; catalyst loading systems internal to the reactor; sonic horns; and engineering services including project management, modeling, start-up/tuning, testing support, and training.

As directed by Burns & McDonnell, not included in pricing are the following items:

- Ductwork to and from SCR reactor
- Structural Steel
- Foundations
- Ammonia storage and supply: including tanks, pumps, dilution air blowers, and AFCU
- Ammonia piping upstream of AIG

- o Insulation and lagging
- o Electrical construction
- o Erection

Also not included in estimated pricing are any boiler modifications and/or equipment additions necessary to attain the requisite economizer exit gas temperature at low loads; ash mitigation devices and modifications to ash handling systems; air heater modifications/replacement; fan modifications/replacement; boiler/precipitator implosion studies or stiffening; rail spur or other ammonia delivery infrastructure; heat tracing; foundations; SCR bypasses; instrumentation and controls and logic information for interface with plant systems; and spare parts.

The development of an order-of-magnitude estimate for an SCR system is a complex process that involves evaluation of many factors including the following:

- Process delivery challenges associated with type of fuel, type/quantity of ash unit operation and required guarantees;
- Arrangement necessary to support catalyst volume requirements, existing unit equipment, anticipated future modifications;
- Access to work areas/constructability;
- Foundations and soil conditions;
- I.D./F.D. fan capacity;
- Pressure drop increase/implosion potential;
- Air heater location/connecting ductwork;
- Steel interferences/reinforcement;
- Span from contract award to commercial operation and acceptable outage duration;
- Type of ammonia system (anhydrous/aqueous/urea conversion).

An engineering evaluation in anticipation of SCR installation permits development of a much more reliable order of magnitude estimate and helps prevent " sticker shock" when a fixed price is developed.

In the preparation of this budgetary estimate, B&W has assumed the use of B&W's technical standards and terms and conditions of sale.

Bowman, Chris

From: Krekeler, Daniel G [dgkrekeler@babcock.com]
Sent: Friday, October 24, 2008 11:50 AM
To: Bowman, Chris; Meinders, John
Cc: Nickey, Michael D; Hansen, Elizabeth A; Gossard, Scott A; Lind, Mel M; Fick, Mike D
Subject: RFQ - SCR For EKPC - Cooper Stations Unit #1 & #2
Attachments: EKPC Cooper SCR BUDGET Basis _3_.pdf

Chris –

The attached document describes the basis of the following budget estimates for SCR system equipment per your request to Michael Nickey dated 9-25-2008 for East Kentucky Power Cooperative's Cooper Station Units #1 and #2.

Unit #1 SCR System per attachment, Engineering and Material only......................................$6,000,000.00 to $8,000,000.00
Unit #2 SCR System per attachment, Engineering and Material only......................................$9,000,000.00 to $11,000,000.00

Recently, we made a visit to site to view the existing site conditions for reference to the installation process and costs; we look forward to an opportunity to discuss this part of the work with you at a later date. We will require a better understanding of the overall project in order to prepare a meaningful price for the SCR installation as well as the integration of this to other portions of the work.

Further, we do not understand the basis of the "inlet" NOx conditions as provided by your request opposite our knowledge of the unit. While we have not done engineering to specifically review the new coals for NOx predictions we think the inlet NOx conditions supplied are lower than B&W would expect. Our concerns include:

- The application of a staged combustion system on these units must consider the unit specific furnace geometry, burner arrangement, and fuels. Overall, these units are not particularly conducive to the application of staged combustion.
- The application of a staged combustion system must carefully consider additional operational concerns including potential increases in slagging/fouling, corrosion, carburization of high temperature boiler components, increase in unburned combustibles, etc.

We have therefore reviewed the costs of a system that would have inlet conditions of .46 lbs/mmbtu on Unit #2 and .50 lbs/mmbtu on Unit #1. Again these NOx numbers, are somewhat arbitrary and do not reflect unit data review or engineering to predict based on the new fuels being considered.

With the above adjustment the price range would be as follows:

Unit #1 SCR System per attachment, Engineering and Material only......................................$7,000,000.00 to $9,000,000.00
Unit #2 SCR System per attachment, Engineering and Material only......................................$10,000,000.00 to $12,000,000.00

Actual commercial guarantees would be negotiated within the context of a formal contract, and would include other factors and criteria, such as the related test methods and commercial issues related to guarantees.

Should you have question or comment on the above/attached please give me a call or respond to this e-mail.

Sincerely,

Daniel G. Krekeler
District Sales Manager
Babcock & Wilcox Power Generation Group
11499 Chester Rd., Ste 701
Cincinnati, Ohio 45246

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power generation group
*Generating Powerful Solutions*SM

RILEYPower
A Babcock Power Inc. Company

Mr. Christopher Bowman
Development Engineer
Burns & McDonnell Engineering

October 17, 2008

Subject: Eastern Kentucky Power (EKP)
Cooper Station Units 1 & 2
SCR Systems Retrofit
Budgetary Proposal

Dear Mr. Bowman:

Riley Power Inc. (RPI), a division of Babcock Power Inc., is pleased to submit our response to the subject inquiry regarding the supply of Selective Catalytic Reduction (SCR) Systems for Eastern Kentucky Power (EKP) Cooper Station, Units 1 & 2.

SCR Technology

Riley Power Inc. (RPI) has over 40,000 MW of installed SCR retrofits in the US coal-fired utility sector. These units have proven to be the best performing, highest NOx removal, most reliable, and lowest long-term repeatable emission rate units, as verified by data reported by the utilities to the EPA. These results are attributable to several technical features of our SCR systems, including:

a) Robust and repeatable mixing technology (patented Delta Wing®) that produces a homogeneous mixture upstream of the catalyst over the boiler operating range;
b) Direct anhydrous ammonia injection without the use of vaporizers and associated equipment, leading to lower first cost, lower operating cost, and higher reliability;
c) Comprehensive physical flow modeling to ensure mixture uniformity, minimal ash layout, and operation without the need for an SCR bypass, with the proven ability to scale up from model results (the preliminary review has been completed for the proposed Martin Lake in-duct design); and
d) In-house boiler expertise, including other manufacturers' units, to assess boiler baseline conditions and address any temperature control issues (e.g., economizer surface modifications) and NFPA related issues, such as boiler stiffening or run back controls.

An additional benefit to our customers, also attributable to our unique SCR technology, is the performance-to-schedule that our designs enable us to deliver:

e) While the overall construction period for an SCR retrofit may be a year or more, the actual tie-in outage requirement can be less than one (1) month.
f) RPI's SCRs are typically commissioned, tested, and meeting guarantees within days of initial full-scale operation.

EKP Cooper Station Information

Limited process and performance data has been provided via several e-mails. This information included unit MW ratings, approximate flue gas flow rates, fuels information, and projected removal efficiency requirements. While significant consideration of the information provided has occurred, a much more detailed effort will be required during the formal proposal. However, the process requirements have been thoroughly evaluated, and found to be very similar to several successfully executed RPI SCR projects.

Scope of Supply

The scope of supply as specified by BMcD (and modified by RPI):

- SCR system w/o economizer gas bypass
- Reactor housing and internal support steel
- Catalyst
- Associated flues and internal flow distribution devices
- ~~Ammonia injection grid~~ RPI Technology for ammonia injection
- System to use 19% aqueous ammonia; ammonia flow control and injection systems, and protection air systems included by RPI
- Internal hoists and monorails for catalyst installation and removal
- Sonic Horns
- Ductwork, within battery limits
- Freight to Somerset, Kentucky

Work provided by others as specified by BMcD (and modified by RPI):

- Ductwork to and from SCR reactor (For "remote" SCR locations)
- Structural Steel
- Foundations
- Ammonia storage and supply: including tanks, pumps, ~~dilution air blowers, and AFCU~~
- Ammonia piping upstream of ~~AIG~~ terminal point at ammonia flow control skids
- Insulation and lagging
- Electrical construction
- Erection & Installation of RPI supplied equipment

BPEI has assumed a "typical" scope of supply for the equipment and systems to be provided, reflective of a conventional, hot side, high dust, vertical SCR reactor layout, ducted directly from the boiler economizer outlets, to the SCR, and back into the main preheater inlets. For the SCR assumed, ammonia flow control and injection systems, including protection air systems, are included as are the reactors, catalyst and catalyst cleaning systems. Excluded are ID or booster fans, LPA and ash removal systems, as well as ductwork, if required, for remote location of the SCR system. Assumed by others are erection and installation, all foundations, all facilities and buildings, DCS supply and integration, and all utilities.

Information Requested by BMcD

Reactor Housing Dimensions:
Unit 1 SCR is a single reactor design, with three (3) catalyst layers (2 initial + 1 spare), 33 (3 x 11 arrangement) catalyst modules per layer, with an overall footprint (excluding platforms and sonic horns), of approximately 24'W X 40'D.
Unit 2 SCR is a single reactor design, with three (3) catalyst layers (2 initial + 1 spare), 64 (8 x 8 arrangement) catalyst modules per layer, with an overall footprint (excluding platforms and sonic horns), of approximately 58'W X 30'D.

Delivery Schedule & Typical Construction Duration:

With regard to schedule, BPEI suggests consideration of the following proposed milestone schedule for smaller SCR projects in general:

Milestone	Project Months
Contract Award & Start Engineering	M1
Detailed Engineering & Design	M1 – M8
Major Equipment Procurement – PO Placement	M4 – M11
Material & Equipment Procurement & Fabrication	M4 – M13
Material & Equipment Delivery to Site	M9 – M15
Construction & Installation – Site Work	M9 – M22
Commissioning & Tests	M21 – M24

While the overall construction period is typically approximately one (1) year, the tie-in outage requirement is minimized to approximately one (1) month. Also, RPI's SCR designs are typically commissioned, tested, and achieving guaranteed performance within the initial weeks of operation. Lastly, the schedule shown above is "typical" or a "go by" useful for planning purposes – RPI has provided completed SCR systems to "fast track" schedules, in less time.

Budgetary Pricing

The budgetary price is **$9,500,000** for the delivered to site SCR Systems and Equipment for Unit 1, and **$12,000,000** for the delivered to site SCR Systems and Equipment for Unit 2. As we previously explained, historically, the erection component of an SCR installation has been equal to 45 – 55 % of the total installed cost, obviously subject to many factors, including of course the final scope of work, specific site issues, and the ease of construction. Please note that our pricing, specifically related to metals, alloys, and process equipment is based upon prices quoted as currently in effect.

Additionally, due to the time allotted and the information available, general arrangements have not been developed. Therefore, consideration of the placement of all equipment and the interconnection of that equipment is also ultimately required. Obviously the eventual result of that work can significantly impact the cost of both the equipment as well as the installation required. BPEI would be happy to further assist BMcD with any or all these issues in the future.

Please note that this submittal is in direct response to the BMcD RFP, received September 25, 2008, via e-mail. Should there be any questions or additional information required, or if we can in any way assist BMcD with your review and evaluation, please contact us immediately.

Please contact us directly at 508-854-3804, or e-mail to: mfreeman@babcockpower.com. We do sincerely thank you for this opportunity, and we look forward to working with BMcD and your team on these projects.

Sincerely,

Michael Freeman
Proposal Manager

SCHUMACHER
CONSULTING LLC
INDUSTRIAL CONSTRUCTION & TURNAROUND CONSULTANT

Prepared for:

Burns & McDonnell

Area Labor Study
for the
East Kentucky Power Cooperative
Cooper Station AQCS
Somerset, KY

October 20th, 2008

SCHUMACHER
CONSULTING LLC
INDUSTRIAL CONSTRUCTION & TURNAROUND CONSULTANT

EKPC
Cooper Station AQCS
Somerset, KY
Area Labor Study
Table of Contents

SCHUMACHER
CONSULTING LLC
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1.0 Purpose

The purpose of this report is to provide information used to support management decisions on contracting strategy, budget preparation, and techniques for attracting and retaining sufficient critical manpower levels to meet project milestones. It is recognized that project scope definitions provided were very preliminary and I have therefore used manhours from similar projects.

Information on the following issues is provided;

- Area competing projects
- Project order of magnitude manhour estimate
- Project schedule and manpower load
- Craft productivity opinion
- Union craft rates / all in rates
- Non-Union craft rates / all in rates
- Worker source

1.1 Area Information

The project site, on a branch of the Cumberland River, is near Somerset, Kentucky.

Cities with significant population and their approximate distance from the site;

City	Population	Distance
Lexington, KY	268,000	81 Miles
Louisville, KY	557,000	134 Miles
Knoxville, TN	180,000	102 Miles
Bowling Green, KY	52,000	111 Miles
Pulaski County, KY	59,200	

1.2 Worker Source - Non Union:

Approximately 60% to 70% of the skilled mechanical trades will be from the gulf coast. The civil trades, semi-skilled, and non-skilled crafts will be hired locally.

The competition for non union skilled workers is on projects nationwide. The rebuilding of hurricane damage, oil refinery expansion, power generation, infrastructure, and government installation projects are exceeding supply by 25% in the gulf coast and is not expected to decline until after 2012. 70% to 80% of the non union contractors are experiencing skilled manpower shortages. These conditions have raised worker pay packages dramatically in recent years. Escalation has been 10% per year.

Workers are demanding and are getting work schedules of 6-10's, incentive pay, and per diems of $75 to $125 per day.

Presently the average 2008 rates of pay at the chevron refinery project in Pascagoula, Mississippi is as follows;

Pipefitter	$27 per hour
Welders	$30 per hour
Electricians	$27 per hour
Civil trades	$25 per hour
Ironworkers	$27 per hour
Painters/Insulators	$22 per hour
Laborers	$20 per hour

Additionally;

- $75 to $100 per day x 7 days/week per diem is paid to all workers.
- $1 per hour safety incentive
- $2.50 per hour welder quality incentive
- 6-10's schedule with time and one half for overtime in excess of 40 hours per week
- A completion bonus is under consideration

1.3 Worker Source: Union

There are 25,000 members belonging to the various building trades unions in Kentucky, as reported by Larry Roberts, President of the Kentucky Building Trades located in Frankfort.

The union locals serving the Cooper Station are as follows (see Attachment 1);

Craft	Local	Location	Members
Boilermakers	40	Louisville	700
Pipefitters	452	Lexington	450
Ironworkers	70	Louisville	800
Electrician	369	Louisville	1200
Millwright	1031	Louisville	1350
Insulator	51	Louisville	850
Operators	181	Louisville	5000
Laborers	576	Louisville	2000
Carpenters	1650	Louisville	2000

It is estimated the unions market share for industrial work is 40% and commercial work is 15% statewide. Presently all locals are reporting full employment, For example, Local 40 Boilermakers have 200 members working out of state, whereas the IBEW local 369 has 100 travelers supplementing their local members.

1.4 Attract and Retain

Research has concluded that the top 5 conditions to attract and retain a skilled workforce as;

- Wage and pay package
- Fringe benefits (medical insurance & savings plan)
- Continuous employment throughout the year
- Safe work site
- Worker respect from employer and owner

1.4.1 - Union

- The union pay packages of wage and fringe benefits are relatively stable compared to the non union practices.

- Wage and fringe rates for each local and the existing contract duration are shown on Attachment 1.
- Escalation is estimated at $1.20 to $2.00 per hour, depending on the craft, for each year beyond the contract termination.
- Escalation for each craft is different because of supply and demand. The overall average is 4.5% per year on total package of wage and fringe(see attachment 2A & 2B). The national average for 2002 thru 2007 was 4.2%.
- It is recommended the following incentives be paid;
    a) Per diem / Subsistence of $40 per day worked for workers whose permanent residence is more than 40 miles from the site. This is in lieu of any unions contract stipulation.
    b) 5-10's pre-outage schedule. I would start the project on 4-10's.
    c) Safety incentive of $.75 per hour accrued for zero recordable weeks worked.

<u>1.4.2 - Non Union</u>

- The 2008 non union pay package for each classification is shown on Attachment 3.
- Escalation is 8% per year which includes work thru the first half of 2012.
- Incentives which are presently given to attract and retain workers are as follows;
    a) Per diem of $100 per day, paid 7 days per week for out of town workers and $50 per day for local workers.
    b) 6-10's pre-outage schedule with time and a half pay for over 40 hours per week.
    c) In & Out travel pay of $500 per out of town worker.
    d) Safety incentive of $.75 per hour accrued for zero recordable weeks worked.
    e) Completion bonus accrued at $1.50 per hour worked and paid if the worker completes his agreed to term of employment.
- It is important to recognize the non-union skilled workers "follow the money"

<u>2.0 Competing Projects</u>

A time scaled barchart of competing projects is shown in Attachment 4.

In these turbulent economic times it is difficult to predict with any certainty which projects are funded and will go forward.

Project activity as known today is expected to keep full employment thru 2012 for both the union and non union workers.

Expected spending for industrial facilities in the U.S. is $270 Billion thru 2010. This equates to a national shortfall for critical skilled crafts thru 2010 a follows:

Boilermakers	<20%>
Ironworkers	<10%>
Pipefitters	<21%>
Electricians	<14%>

A shortfall in the construction industry does not mean a lack of available people, but rather a lack of trained, skilled, and productive workers.

Some "mega-projects" in the Midwest are;

Owner	Location	Description	Complete
ConocoPhillips	Wood River, IL	$4 Billion Expansion	2012
BP	Whiting, IN	$6 Billion Expansion	2014
Peabody	Marissa, IL	2 x 850MW CFB	2012
KCPL	Iatan, MO	1 x 850MW CFB	2010
Sinclair	Tulsa, OK	$1.4 Billion Coker	2012
Basin Electric	Selby, SD	1 x 750MW CFB	2014
Ameren	MO & IL	$1.1 Billion AQCS	2013

3.0 Project Manhour Estimate

The scope of this project is very preliminary and therefore the manhours are to be considered "order of magnitude".

3.1 Manhours

Manhours for work activities from three similar projects are summarized on Attachment 5. These have a productivity rate of 1.2. Total craft manhours are estimated to be 750,000.

3.2 Pre-Outage / Outage

Attachment 6 shows the manhour split between pre-outage and outage work, for each major craft and the corresponding average workers per day load. It is expected peak loading will be;

Pre-Outage	210 workers per day
Outage	190 workers per shift x 2 shifts

3.3 Craft Pay Rates / All in Rates

3.3.1 Union Rates

Attachment 2 shows the calculations for the project average rate of wage & fringe, escalation, premium pay for 5-10's pre, 7-10's outage, and incentives. Contractor costs are then added to achieve an "all-in" rate.

The all in union rate is $100.55.

3.3.2 Non-Union Rates

Attachment 3 shows the above listed cost components.

The Non-Union total "all in" rate is $112.45 per hour.

4.0 Project Schedule

The preliminary schedule shown on attachment 7 was developed principally to determine peak manpower loading. Activity logic was considered for each work item.

The outage schedule is affected by crane access and limiting capacity.

It is estimated that 20 pieces of duct, each weighing 40,000 lbs will be set during the outage. Certain pieces will have to be set at a 150' crane radius, which is limiting the duct size.

Other preceeding activities of abatement and demo hold off the setting of ductwork until week 6.
It is my opinion the outage schedule will be 10 weeks.

5.0 Constructability

This site presents some challenges for crane access and placement, thus affecting the schedule. A detailed constructability study is recommended after the scope has been developed further. During the outage 1-M2250 will be staged southeast of the existing precipitator for duct lifts and tie-ins. Leveling and rock build up will be required on the south side of the new duct for crane travel. Crane mats will be required to protect underground piping.

Crane and truck access must be provided on the east end of the new scrubber. 2- M2250's will be required pre-outage. Crane capacity with 200' of boom is:

60' Radius - 165,000 Lbs.
100' Radius - 82,000 Lbs.
160' Radius - 37,000 Lbs

Crane costs have escalated drastically over the last two years due to unprecedented demand. 2008 costs for an M2250 Series 3:

Bare rent (176 hrs/mo)	$50,000 / Mo
Fuel	$32 per hour
Maintenance	$2,000 / Mo
Insurance	$3,000 / Mo
Assembly and knock down	$315,000
Freight in & out	$100,000
Escalation	15% to 20% per year

6.0 Productivity Opinion:

My experience working with the union trades in the area has resulted in good craft productivity.

Most issues affecting productivity are contractor management failures and lack of skilled manpower. Refer to best practices in the summary.

The factors used for estimating are based as a multiplier of the gulf cost standards. The results in recent years on large industrial projects have the multiplier at 1.2 times standards for the best experiences. I would expect productivity factors at;

Craft	Union	Non-Union
Piping	1.3 x G.C.S.	1.5 x G.C.S.
Electrical	1.2 x G.C.S.	1.2 x G.C.S.
Boilermaker	1.2 x G.C.S.	1.3 x G.C.S.
Structural	1.3 x G.C.S.	1.3 x G.C.S.
Millwrights	1.4 x G.C.S.	1.4 x G.C.S.
Civil	1.2 x G.C.S.	1.2 x G.C.S.

7.0 Summary

7.1 Incentives

7.1.1 Per Diems

Non-union: most skilled crafts will be from out of state. Their costs for living out of town is $50 to $70 per day. The standard per Diem is $100 per day paid 7 days per week. Local hires are paid $50 per day. The difference between cost and paid amounts is looked upon by the worker as tax free wages.

Union: Most local agreements do not require travel and living subsistence pay. The national agreements, i.e. NMAPC, do not require payment for travel and living. However, it is recommended a $40 per days worked subsistence be paid for workers who travel more than 40 miles to the site.

7.1.2 Travel Pay
Non-union: For workers who are not local hires, a one time $500 in and out travel payment is expected today.

Union: Not Required.

7.1.3 Overtime
Non-union: 6-10's expected.
Union: 5-10's is recommended

7.1.4 Incentive Pay
Non-union: Safety bonus of $.75 per hour accrued for zero recordable weeks worked. Completion bonus of $1.50 per hour accrued for satisfactory completion of employment.

Union: Safety bonus of $.75 per hour accrued for zero recordable weeks worked.

7.1.5 Safety
The jobsite safety program must be a serious undertaking totally supported by the owner, construction manager, and direct hire contractors.

Zero recordables must be the stated goal.

A mandated substance abuse policy with pre-employment, for cause, and random screening must be implemented.

I recommend the adoption of the owner's policy or the contractors after a comprehensive review of the content, in lieu of using the substance abuse screening programs presented by the unions.

Tight substance abuse control is the basis for jobsite safety excellence.

7.2 Constructability
It is recommended a project constructability study be performed after the work scope determination is nearly complete to optimize cost and schedule.

This jobsite is complex due to the limited areas for staging, fabrication and assembly, transporting and rigging of components. These limiting factors will impact the project schedule and outage duration.

7.3 All In Rates
It is expected that sufficient manpower can be attracted and retained using the incentives presented. It is possible, with an economic downturn, that overtime, per diems, and completion bonuses may be reduced or not be required at all.

Labor escalation would be in the 4% to 5% per year range.

The 12% contractor overhead and profit factor on all costs except subcontracts, contemplates a fee type contract with labor costs reimbursable. A lump sum contract markup would be in the 18% to 22% range, including contingency. It is very unlikely you would find contractors to bid lump sum in the current market.

7.4 Union Agreement
Even after the unions have lost over 80% of the market share, it still takes a great deal of skill to manage the work force on a union job. Owners and contractors must encourage the adoption of business principles by the unions rather than the same old politics to manage union enterprises.

There are national union agreements such as the NMAPC, General Presidents, and NCA that address most of the problems of the past but it takes the managing contractor to exercise control and utilize the content of those agreements to manage the jobsite.

I recommend the NMAPC agreement for your project. This is a national agreement which has all crafts bound to the same agreement and language regardless of their present membership in the AFL-CIO Building Trades. The owner or construction manager can apply for the agreement or your bid documents can stipulate each contractor to be in possession of the agreement. Contact www.NMAPC.org.

7.5 Best Practices
It has been my experience that the following best practices will have a positive influence on productivity;

1. The contractor must be committed to the zero injury culture and techniques. The CII has recognized a correlation between poor productivity and poor safety performance.

2. Detailed planning and scheduling by the contractor. This must be a serious effort. The plan must run the job. The contractor must have these resources.

3. Timely delivery of materials and equipment.

4. Minimize engineering and fabrication changes.

5. Alcohol and substance abuse testing, including random.

6. Timely delivery of engineering and technical information.

7. The contractors must provide ample tools and equipment.

8. The contractor must have experienced and competent staff and supervision.

9. The contractor must control the labor on site. Utilize and understand the labor agreement management article to its fullest extent.

10. Control work jurisdiction between the crafts.

11. Negotiate a crew mix within the crafts using apprentices.

12. Avoid saturated manning and high work density.

13. Avoid shift work and overtime.

14. Promote craft ownership in the project. This begins with the safety initiative.

15. Minimize worker turnover. A 10% increase in turnover results in a 2.5% increase in labor costs plus productivity and safety impacts.

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Attachment #1

Union Craft Labor Rate

DISCIPLINE	LOCAL	UNION JM WAGE	UNION JM FRINGE	CONTRACT THRU	SUBSIS.	NO. OF MEMBERS	NO. OF APPREN.	COMMENTS
Boilermaker	L 40	$31.89	$15.71	10/1/08	No	600	100	Ray Parrott 270-769-3022
Pipefitter	L 452	$29.50	$14.56	10/31/11	In fringe	450	Incl.	Robert Johnson 859-252-8337
Ironworker	L 70	$23.93	$17.09	5/31/09	No	800	Incl.	Ronnie Lynch 502-637-8796
Electrician	L 369	$29.27	$13.28	6/1/11	No	1,200	Incl.	Darrell Lawson 502-368-2568
Millwright	L 1031	$22.77	$12.78	5/31/09	No	1,350	Incl.	Anthony Holbrook 859-402-8653
Insulator	L 51	$23.61	$9.81	5/31/09	No	850	Incl.	Dan Kahl 502-893-4040
Operator	L 181	$23.85	$12.40	5/31/09	No	5,000	Incl.	Jim Jones 859-278-8458
Carpenter	L 1650	$19.65	$9.63	5/31/09	No	2,000	Incl.	Jerry Yates 859-252-5254
Laborer	L 576	$16.62	$7.53	6/30/09	No	2,000	Incl.	Roy West 502-375-0581

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Rev. Date: 10/9/2008

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Cooper Station AQCS

Attachment #2

Average Composite Union Craft Labor Rate

DISCIPLINE	Years	Escalation Per Year	Escalation thru 5/2012	Wage thru 5/2012	Fringe thru 5/2012	% OF SCOPE	VALUE OF WAGE	VALUE OF FRINGE	Comments
Boilermaker	3.5	$2.00	$7.00	$36.90	$18.21	50.00%	$18.45	$9.11	
Pipefitter	0.5	$2.00	$1.00	$30.50	$14.56	6.00%	$1.83	$0.87	
Ironworker	3	$2.00	$6.00	$28.93	$18.09	9.00%	$2.60	$1.63	
Electrician	1	$2.00	$2.00	$30.27	$14.28	12.00%	$3.63	$1.71	
Millwright	3	$1.65	$4.95	$25.77	$14.78	4.00%	$1.03	$0.59	
Insulator	3	$1.50	$4.50	$26.61	$11.31	5.00%	$1.33	$0.57	
Operator	3	$1.50	$4.50	$26.85	$13.90	8.00%	$2.15	$1.11	
Carpenter	3	$1.50	$4.50	$22.65	$11.13	3.00%	$0.68	$0.33	
Laborer	3	$1.20	$3.60	$19.62	$8.13	3.00%	$0.59	$0.24	
					Total	100.00%	**$32.29**	**$16.17**	

Average wage	$	32.29	
5-10's & 7-10's Premium Time	$	4.52	14% x Wage
Average Fringe	$	16.17	
Taxes & Insurance	$	11.04	30% x Wage
Safety Incentive	$	0.75	
*Subsistence / Travel	$	4.00	$40 / Day * Not required by Agreement, suggest $40 per day
Subtotal	**$**	**68.78**	
ST, Consum., Eqpt.	$	10.00	
Contractor staff	$	8.00	
Misc.	$	3.00	
Total	**$**	**89.78**	
12% OH & P	$	10.77	
Total All In Rate	**$**	**100.55**	

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Cooper Station AQCS

Attachment #2A

Union Craft Escalation

Discipline	2008 Wage	2008 Fringe	2008 Total	2012 Total	Total % Increase	Per Year for 3 Years	% of Scope	2008 Value	Comments
Boilermaker	$31.89	$15.71	$47.60	$55.11	15.8%	5.3%	50%	$23.80	
Pipefitter	$24.55	$11.76	$36.31	$45.00	23.9%	8.0%	6%	$2.18	
Ironworker	$23.93	$17.09	$41.02	$47.02	14.6%	4.9%	9%	$3.69	
Electrician	$27.33	$12.22	$39.55	$44.55	12.6%	4.2%	12%	$4.75	
Millwright	$22.77	$12.78	$35.55	$40.55	14.1%	4.7%	4%	$1.42	
Insulator	$23.61	$9.81	$33.42	$37.92	13.5%	4.5%	5%	$1.67	
Operator	$23.85	$12.40	$36.25	$40.75	12.4%	4.1%	8%	$2.90	
Carpenter	$19.65	$9.63	$29.28	$33.78	15.4%	5.1%	3%	$0.88	
Laborer	$16.22	$7.53	$23.75	$27.75	16.8%	5.6%	3%	$0.71	

Total Wage and Fringe 2008/2009 **$42.00**

Value used on Attachment 2 for 2012

Wage	$32.29
Fringe	$16.15
Total Wage and Fringe 2012	**$48.44**

Escalation for Period 2008/09 to 2012 **15.3%**

Escalation Per Year (15.3 / 3.5 years) **4.4%**

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Cooper Station AQCS

Attachment #2B

All In Rate Escalation

		UNION 2008
Average Wage & Fringe		
Wage		$28.00
Fringe		$14.00
5-10's & 7-10's Premium time	14%	$3.92
Taxes and Insurance	30%	$9.58
Safety		$0.75
Sub & Travel		$3.00
Subtotal		**$59.25**
ST&C, Eqpt.		$8.50
Contractor Staff		$6.00
Misc.		$2.50
Subtotal		**$76.25**
12% Overhead & Profit	12%	$9.15
Total 2008		**$85.40**
Total 2012		**$100.50**
Escalation 2008 to 2012		**17.69%**

		NON-UNION 2008
Average Wage & Fringe		
Wage		$31.63
Fringe	10.0%	$3.16
6-10's & 7-10's	20.0%	$6.33
Taxes and Insurance	30.0%	$11.39
Safety		$0.75
Completion Bonus		$1.50
In & out		$0.25
Per Diem		$11.67
Subtotal		**$66.68**
ST&C, Eqpt.		$8.50
Contractor Staff		$6.00
Misc.		$2.50
Subtotal		**$83.68**
12% Overhead & Profit	12.0%	$10.04
Total 2008		**$93.72**
Total 2012		**$112.40**
		19.94%

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Rev. Date: 10/9/2008

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Cooper Station AQCS

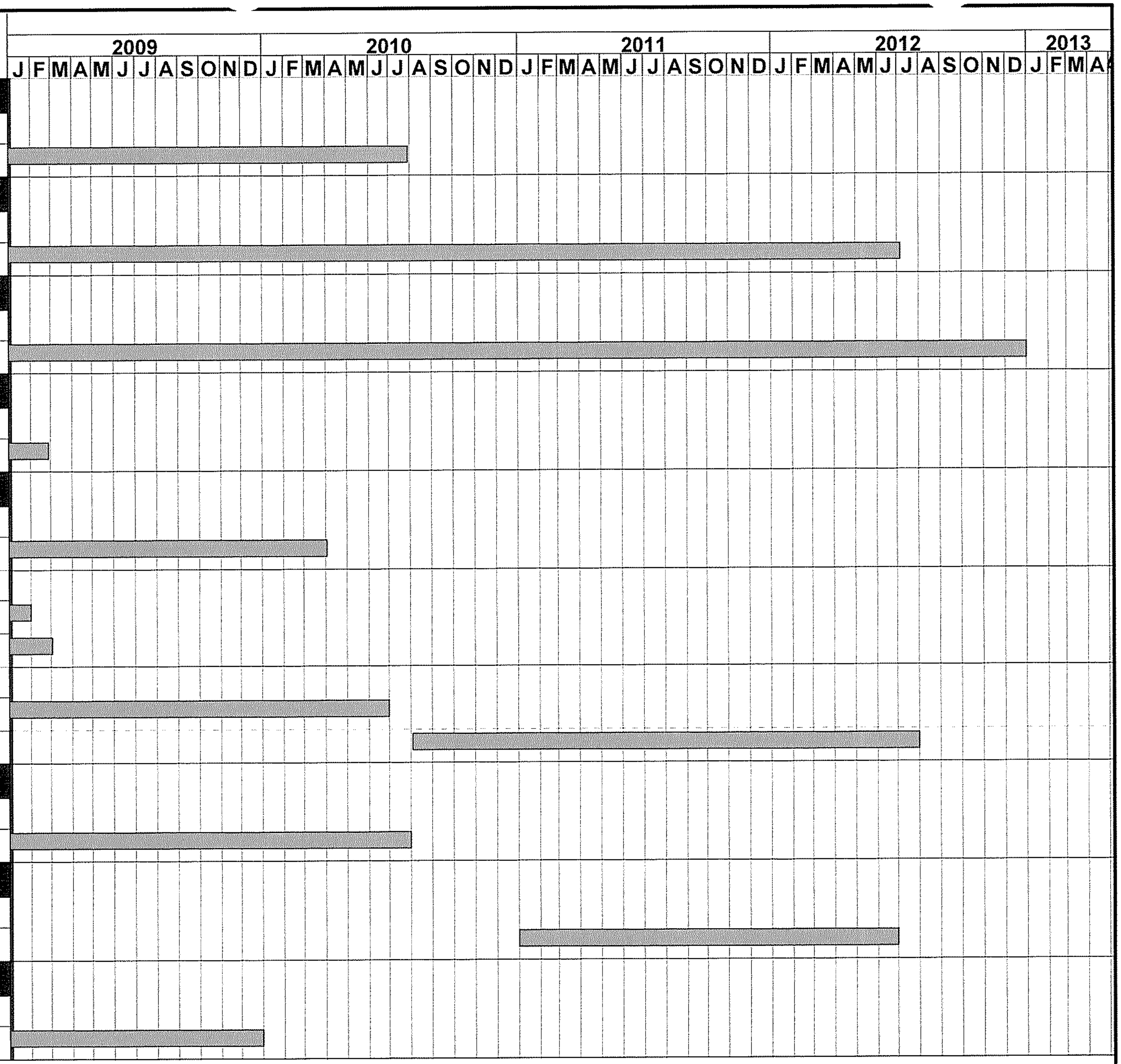
Attachment #3

Average Composite Non-Union Craft Labor Rate

DISCIPLINE	% OF SCOPE	2008 WAGE	Value	Comments
Boilermaker	35.00%	$ 30.00	$ 10.50	
Boilermaker Welder	20.00%	$ 35.00	$ 7.00	
Pipefitter	3.00%	$ 32.00	$ 0.96	
Pipefitter Welder	3.00%	$ 35.00	$ 1.05	
Ironworker	9.00%	$ 30.00	$ 2.70	
Electrician	12.00%	$ 34.00	$ 4.08	
Millwright	4.00%	$ 32.00	$ 1.28	
Operator	8.00%	$ 32.00	$ 2.56	
Carpenter	3.00%	$ 28.00	$ 0.84	
Laborer	3.00%	$ 22.00	$ 0.66	
Total	100.00%		$ 31.63	

Average Wage	$ 31.63	
Escalation	$ 7.60	3 years x 8% (2012)
6-10's & 7-10's Premium Time	$ 7.85	20% x Wage
Avg. Fringe	$ 4.00	10% x Wage
Taxes & Insurance	$ 14.15	30% x Wage
Per Diem	$ 11.67	7 Days x $100
In & Out Travel	$ 0.25	$500
Subtotal	**$ 77.15**	
Safety Incentive	$ 0.75	
Completion Bonus	$ 1.50	
Total	**$ 79.40**	
Small tools and Consumables	$ 3.00	
Small Equipment	$ 1.00	
Large Equipment	$ 6.00	Cranes less than 150T
Contractor staff	$ 8.00	
Misc.	$ 3.00	
	$ 100.40	
OH & P	$ 12.05	12%
Total All In Rate (2011)	**$ 112.45**	

Act ID	Activity Description
Alliance Coal	
Morganfield, KY	
280	Coal Mine Expansion $275 Million
American Municipal Power	
Hawesville, KY	
230	Hydro power expansion $125 Million
BP	
Whiting, IN	
320	Refinery Expansion - $6 Billion
Brazeway	
Hopkinsville, KY	
270	Aluminum Extrusion Plant $42 Million
East Kentucky Power Cooperative	
Ford, KY	
210	Unit 3 & 4 Repowering Project $125 Million
Maysville, KY	
215	Unit 4 -New 278 MW coal fired boiler $475 Mil.
220	Unit 2 -508 MW AQCS $159 Million
Trapp, KY	
200	Unit 1 -New 278 MW coal fired boiler $600 Mil.
205	Unit 2 -New 278 MW coal fired boiler $500 Mil.
EON U.S.	
Bedford, KY	
240	Unit 2 - New 750 MW coal fired boiler $1.1 Bil.
FFP Corporation	
Hickman, KY	
250	Hydro Power Project $100 Million
Genesis Development	
Pine Mountain, KY	
260	100 MW Wind Farm $170 Million

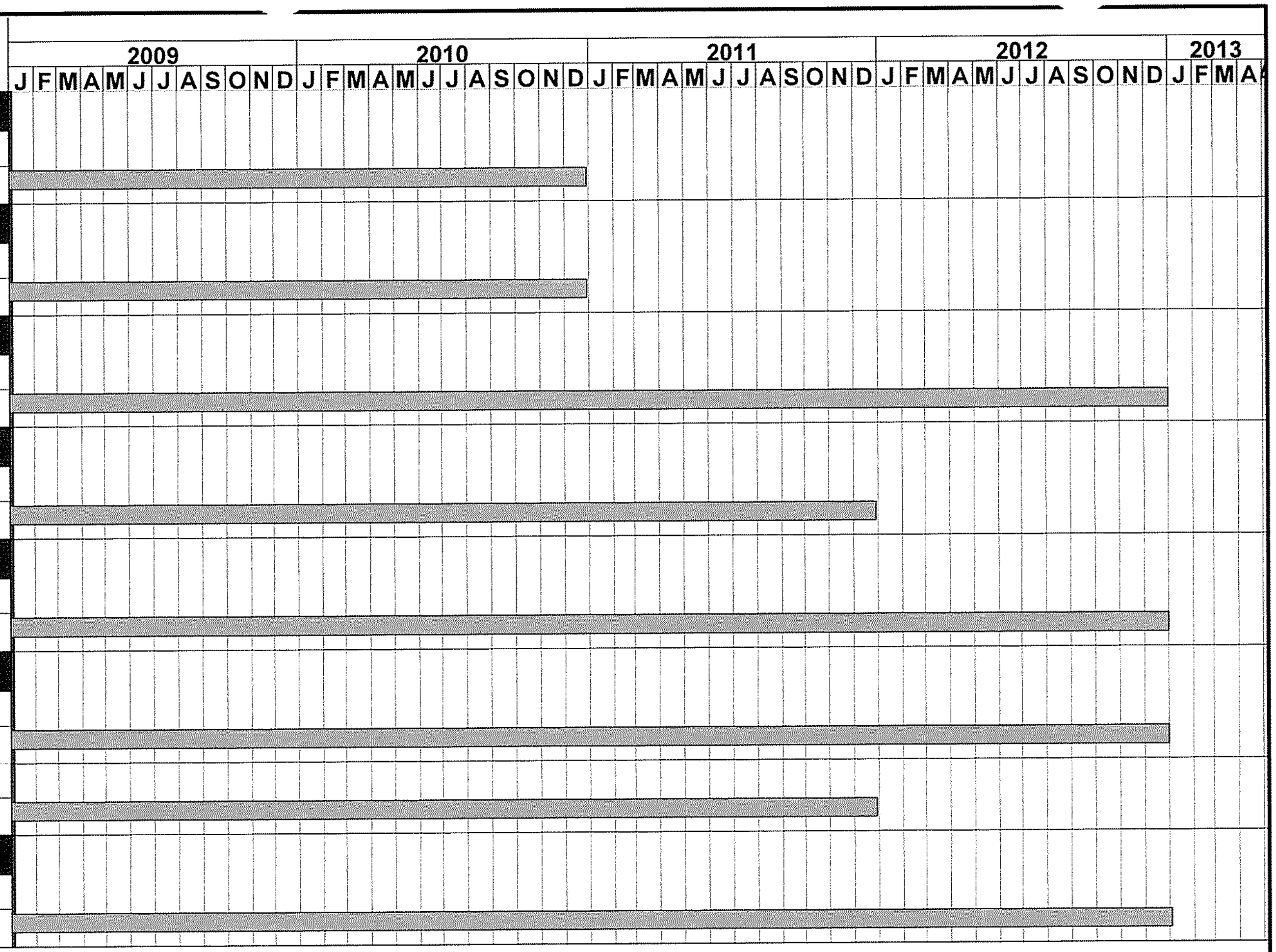


Start Date	01-JAN-09
Finish Date	04-JAN-13
Data Date	01-JAN-09
Run Date	19-OCT-08 19:13

East Kentucky Power Cooperative

Mid-South Area Workload
Attachment #4

Act ID	Activity Description
Chemical Plants	
Kentucky	
290	Capital and maintenance projects $211 Million
Longview Power	
Maidsville, WV	
130	New 695 MW coal fired boiler
Marathon Oil Company	
Ashland, KY	
340	Turnaround / minor projects $50 Million
Ohio Power Projects	
Southern Ohio	
300	Southern Ohio Power Projects - $2.5 Billion
Peabody Energy	
Marissa, IL	
330	2 x 850 MW Power Plant $3.2 Billion
Misc. Industrial Projects	
Indiana	
315	Misc Industrial Projects - $13 Billion
Tennessee	
310	Misc Industrial Projects - $6 Billion
Tennessee Valley Authority	
Spring City, TN	
305	1220 MW Nuclear Plant $2.5 Billion



Schumacher Consulting, LLC Rev. Date: 10/15/2008

EKPC

Cooper Station AQCS

Attachment #5

Rough Order of Magnitude Manhours

Dry Scrubber with Baghouse	520 MW	320 MW	260 MW	* 230 MW	Schedule
Asbestos Abatement	9,500	10,700	9,500	9,500	outage
Demo duct and steel, Tie in	20,000	17,000	13,600	15,000	outage
Demo Precipitator	0	0	0	5,000	outage
Sitework	5,000	2,600	3,200	5,000	3 mos
Ductwork, reinforcing, dampers	135,000	152,800	162,500	150,000	Pre & outage
Structural	19,000	8,300	4,800	12,000	2 mos
Foundations	47,000	32,200	13,100	20,000	4 mos
ID Fans	9,000	7,700	5,400	6,000	1.5 mos
Lime unloading & storage	11,000	0	0	10,000	2 mos
Absorber modules	202,000	158,400	122,200	125,000	6 mos
Maintenance bldg.	4,800	3,000	1,800	2,000	1.5 mos
Absorber waste handling / Silo	8,400	0	0	6,000	
Misc tanks / Loader	2,100	1,000	900	1,000	
MU Water, tubing, BOP Piping	14,600	21,700	2,000	20,000	
Baghouse / Ash handling	141,400	106,700	63,000	63,000	6 mos
Relocate equipment	5,500	15,000	15,300	12,000	
Electrical	107,400	27,500	25,800	30,000	
Total	741,700	564,600	443,100	491,500	
SCR - 450 MW	413000				
SCR - 250 MW	250000			250,000	12 mos
Total				**741,500**	

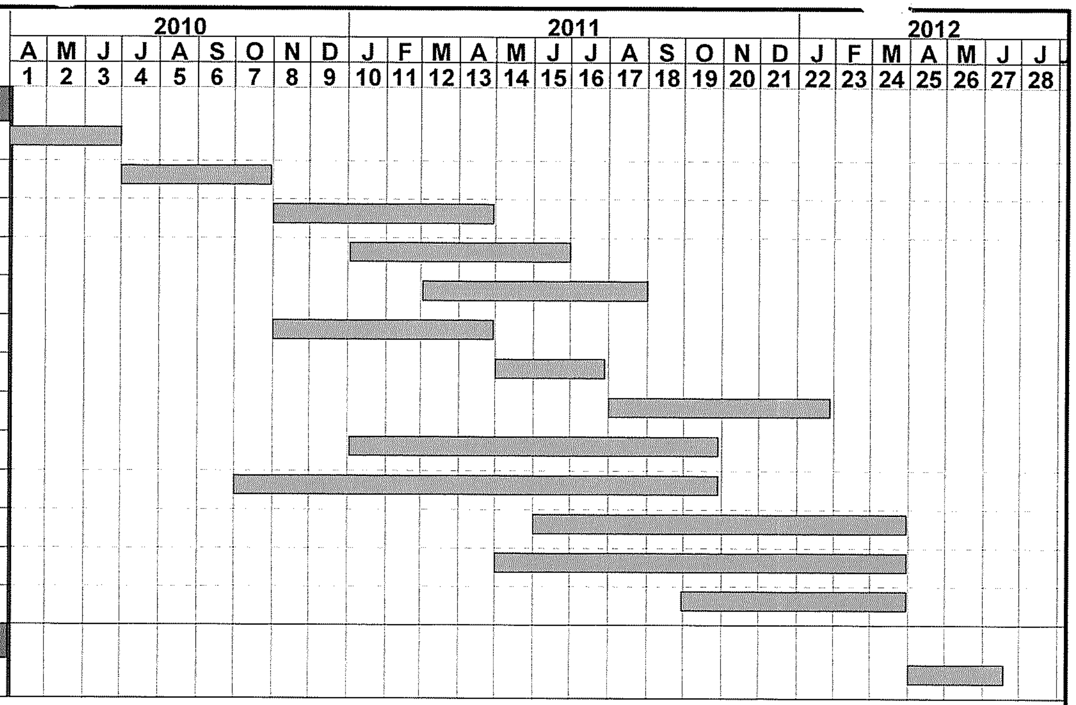
Schumacher Consulting, LLC

Rev. Date: 10/15/2008

EKPC
Cooper Station AQCS
Attachment #6
Craft Manhour Breakdown

					Pre: 5-10's		Outage: 7-10's		
DESCRIPTION	% OF SCOPE	MHRS	PRE-OUTAGE	OUTAGE	WORKERS/ DAY	MOS.	WORKERS/ SHIFT	WEEKS	COMMENTS
Scrubber / Baghouse / SCR: 750,000 Mhs						24		9	
Civil / Foundations	10.0%	75,000	65,000	10,000	33	9	18	4	
Boilermaker	55.0%	412,500	370,000	42,500	94	18	34	9	
Ironworker	9.0%	67,500	50,500	17,000	38	6	24	5	
Millwright	4.0%	30,000	15,000	15,000	23	3	27	4	
Pipefitter	6.0%	45,000	35,000	10,000	27	6	8	9	
Electrician	12.0%	90,000	45,000	45,000	34	6	36	9	
Other	4.0%	30,000	15,000	15,000	34	2	36	3	
		750,000	**595,500**	**154,500**					
					Peak		Peak		
					210		190 / Shift		

Act ID	Activity Description	Early Start	Early Finish
Non-Outage Work			
10	Sitework	01-APR-10	30-JUN-10
20	Foundations	01-JUL-10	29-OCT-10
30	Structural	01-NOV-10	29-APR-11
40	Erect Scrubber	03-JAN-11	01-JUL-11
50	Erect Baghouse	03-MAR-11	31-AUG-11
60	Misc Equipment	01-NOV-10	29-APR-11
70	ID Fans	02-MAY-11	29-JUL-11
80	BOP Piping	01-AUG-11	27-JAN-12
90	Erect SCR	03-JAN-11	28-OCT-11
100	Fabricate Ductwork	01-OCT-10	28-OCT-11
110	Erect Ductwork	01-JUN-11	30-MAR-12
120	Electrical	02-MAY-11	30-MAR-12
490	Check out & Commissioning	30-SEP-11*	30-MAR-12
Outage Work			
300	Outage Tie-ins	02-APR-12	18-JUN-12



Start Date 01-APR-10
Finish Date 18-JUN-12
Data Date 01-APR-10
Run Date 19-OCT-08 19:11

EKPC
Cooper Station AQCS
Project Schedule

Attachment #7

Sheet 1 of 1
EKP1

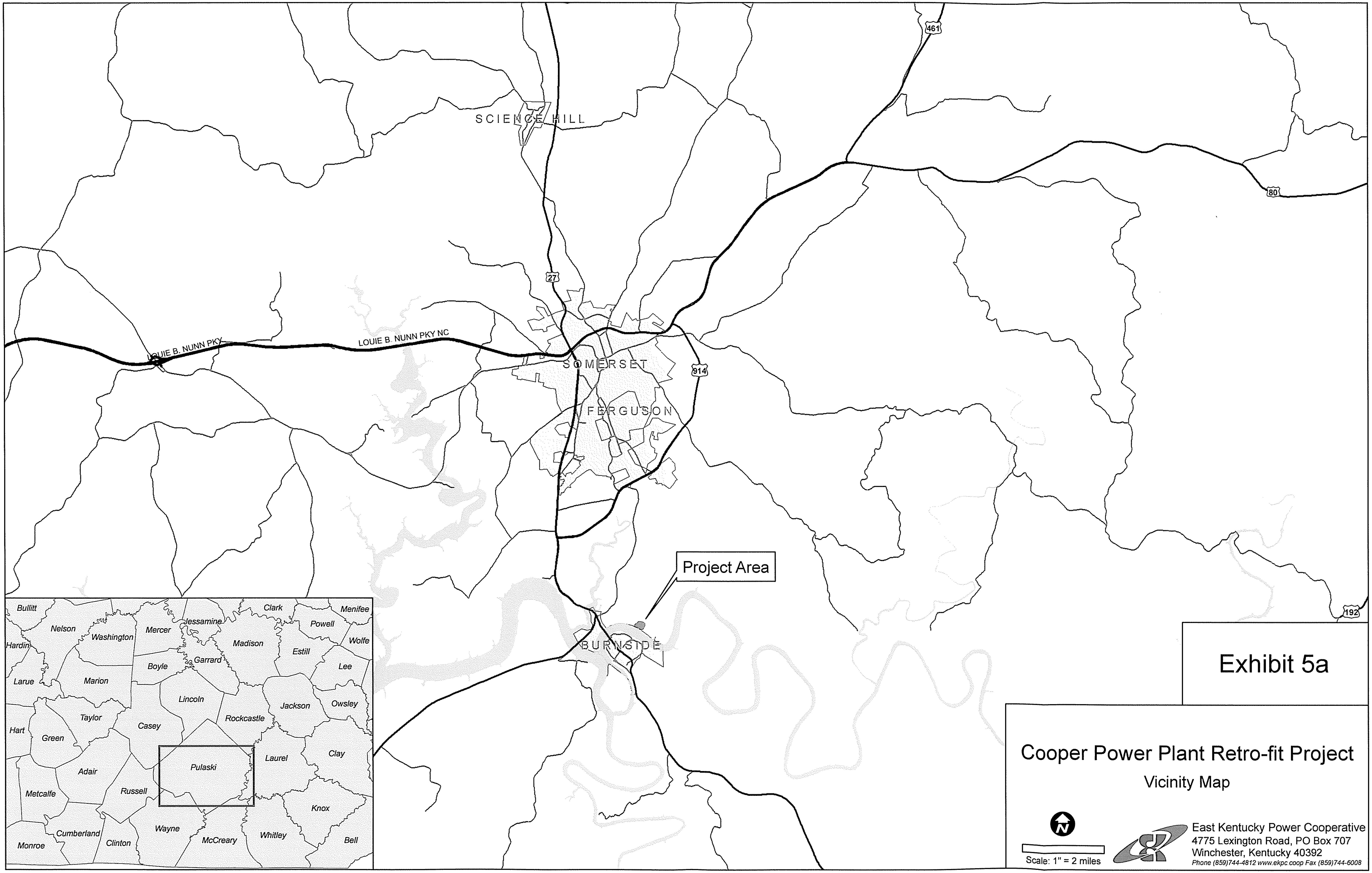
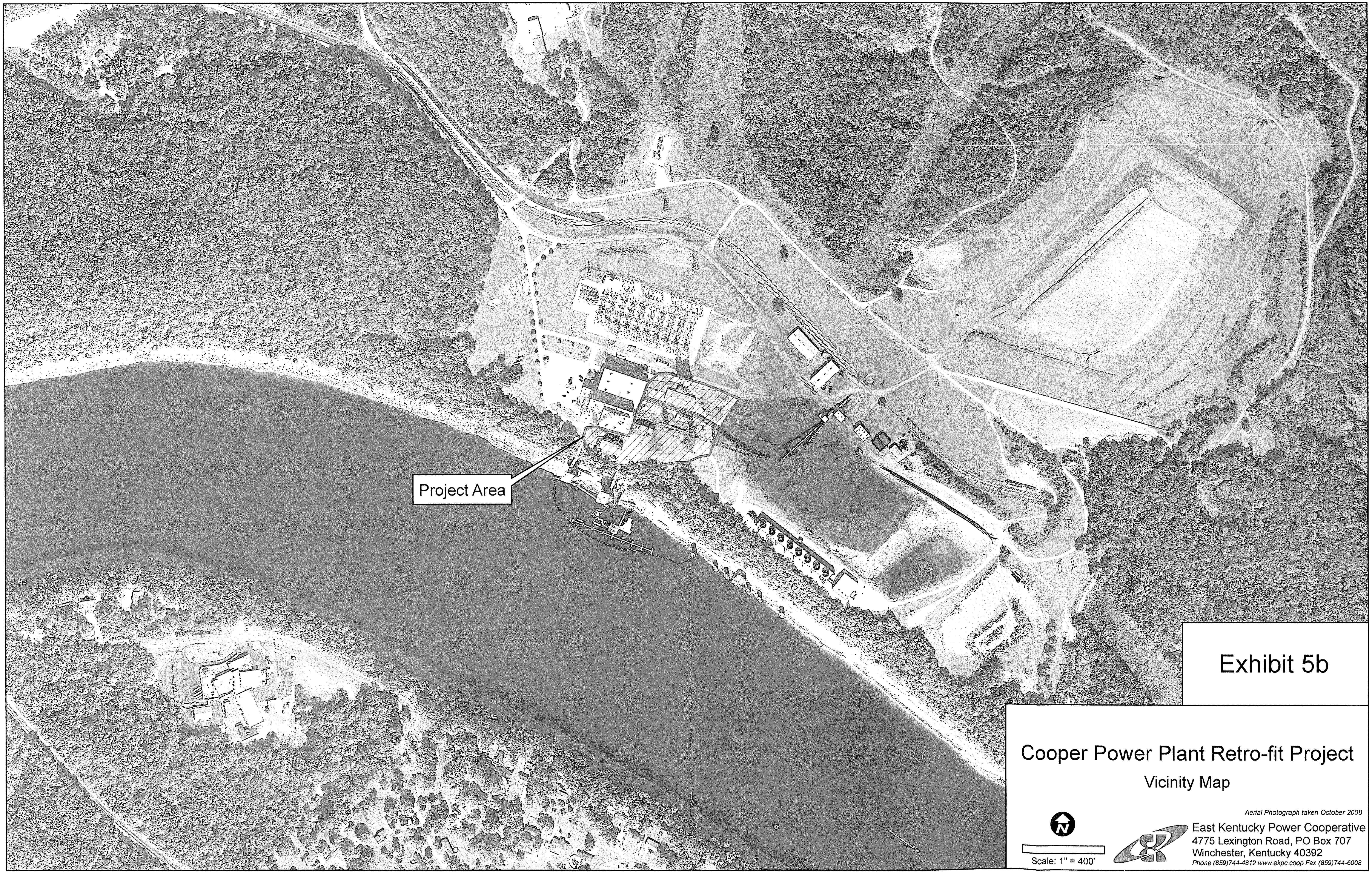


Exhibit 5a

Cooper Power Plant Retro-fit Project

Vicinity Map

East Kentucky Power Cooperative
4775 Lexington Road, PO Box 707
Winchester, Kentucky 40392
Phone (859)744-4812 www.ekpc.coop Fax (859)744-6008


Project Area
Exhibit 5b
Cooper Power Plant Retro-fit Project
Vicinity Map
Aerial Photograph taken October 2008
Scale: 1" = 400'
East Kentucky Power Cooperative
4775 Lexington Road, PO Box 707
Winchester, Kentucky 40392
Phone (859)744-4812 www.ekpc.coop Fax (859)744-6008

Large map

Given to

GIS to Scan

on 11/17/08

Cooper Station Unit 2 AQCS System
Estimated Annual Operating Costs
November 2008

Annual Expense		
Interest	$	19,440,000
Depreciation		18,000,000
Taxes and Insurance		576,000
TIER		8,748,000
O&M		20,777,696
Total	$	67,541,696

Exhibit 7

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	**CASE NO. 2008-**

DIRECT TESTIMONY OF ROBERT M. MARSHALL
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, business address and occupation.

A. My name is Robert M. Marshall and my business address is East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am President and Chief Executive Officer.

Q. Please state your education and professional experience.

A. I received a bachelor of science degree in civil engineering from the Clemson University. I also completed a program in management development from the Harvard Business School. I have been employed in the utility industry for thirty-nine years, serving in a variety of management positions at Florida Power & Light and as President and CEO at Coosa Valley Electric Cooperative in Alabama. I was President and CEO at Owen Electric Cooperative for about seven years.

Q. Please provide a brief description of your duties at EKPC.

A. As CEO, I am responsible for managing the Cooperative's business on a day-to-day basis. I develop and recommend to the EKPC Board of Directors ("Board")

EKPC's objectives and policies, short- and long-range plans, and annual budgets and work plans. I administer the Board's approved wage and salary plan, authorize prudent investments, administer the budget, implement policies, plans and programs established by the Board, ensure an appropriate organizational structure, negotiate contracts, and submit periodic and special reports to the Board on operations, financial issues, budgets, power supply, rates, construction, and other areas. This is just a sampling of the responsibilities established for the President and CEO in EKPC Board policy.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a high level overview of why EKPC is seeking this Certificate of Public Convenience and Necessity ("CPCN").

Q. Why is EKPC seeking a CPCN for an Air Quality Control System ("AQCS") at Cooper Station?

A. EKPC filed a Consent Decree with the United States Environmental Protection Agency ("EPA") that the Court entered on September 24, 2007. In the Consent Decree, the EPA gave EKPC the option to either install and continuously operate NO_x emission controls and SO_2 emission controls at Cooper Unit 2 by December 31, 2012 and June 30, 2012, respectively, or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012. EKPC has a third option to retire Dale Units 3 and 4 by December 31, 2012 and repower those units by May 31, 2014. EKPC, with consulting support from Burns & McDonnell, evaluated its options to comply with the Consent Decree requirements and has concluded its best alternative is to install and continuously operate NO_x and SO_2

emission controls for Cooper Unit 2. Therefore, EKPC is now seeking a CPCN for the needed facilities from the Kentucky Public Service Commission.

Q. How will this proposed course of action benefit EKPC's members?

A. By installing an AQCS at Cooper Unit 2 and keeping the Dale units in service, EKPC will preserve valuable baseload generation to serve its members. Cooper Station is a proven generation asset for the EKPC system. Continued environmentally compliant operation of this unit has immense value to the EKPC members. Dale Station Units 3 and 4 are proven baseload generation assets to the EKPC system as well. Shutting these units down would cause economic hardships on the EKPC members and create transmission and voltage operational issues on the Central Kentucky transmission system. By preserving proven baseload generating units, EKPC reduces its dependence on outside markets and Kentucky's dependence on out of state generation resources.

Q. What studies did EKPC conduct to determine this course of action?

A. A complete discussion of the studies to determine the need and project alternatives is contained in the Prepared Testimony of Julia J. Tucker, attached as Application Exhibit 9.

Q. Once EKPC chose to construct an AQCS at Cooper Station, how was the proposed technology selected?

A. A consulting engineer was selected and evaluations were performed to develop and compare alternative systems. This will be further discussed in the Prepared Testimony of John R. Twitchell, attached as Application Exhibit 10.

Q. How does EKPC intend to finance the proposed facilities?

A. EKPC's plans to use Rural Utilities Service financing for these facilities are discussed in the Prepared Testimony of David G. Eames, attached as Application Exhibit 8.

Q. Do you believe that the proposed AQCS facilities are the most prudent way for EKPC to meet its identified environmental obligations?

A. Yes. I believe that these facilities are the best way for EKPC to meet that identified need.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	**CASE NO. 2008-**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Robert M. Marshall, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Subscribed and sworn before me on this 12th day of November, 2008.

Claudia N. Embs
Notary Public

My Commission expires: March 23, 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)	**CASE NO. 2008-**

DIRECT TESTIMONY OF DAVID G. EAMES
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, business address and occupation.

A. My name is David G. Eames and my business address is East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am Chief Financial Officer for EKPC.

Q. Please state your education and professional experience.

A. I received a Bachelor's degree in Engineering from Northeastern University in 1971 and a Master's degree in business Administration in 1976 from the University of Michigan. I am a licensed professional engineer and a certified public accountant in the Commonwealth of Kentucky. In addition, I have attended and participated in several seminars and supplemental training courses over the years. I have been employed by EKPC since January 1979 and have occupied my current position within the EKPC organization since September 1985.

Q. Please provide a brief description of your duties at EKPC.

A. I am responsible for all aspects of finance, accounting, performance measures and risk management at EKPC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain how EKPC is going to finance the capital costs of this project and how EKPC plans to recover the costs.

Q. Has EKPC purchased any equipment or made any financial commitments to equipment for this project?

A. No purchases or commitments for equipment have been made. Although Burns & McDonnell has collected vendor input for project estimate purposes, requests for formal vendor proposals for the design, manufacture and installation of the pollution control equipment must be issued in early 2009.

Q. How will EKPC finance the construction of this facility?

A. EKPC will seek Rural Utilities Service ("RUS") funding for this project.

Q. Is the cost of this project included in EKPC's current rate case?

A. No, the cost of this project is not included in EKPC's application for a general rate increase (Commission Case No. 2008-00409.) However, we believe this project is eligible for recovery in EKPC's environmental surcharge. EKPC will file an application with the Commission for approval of an amendment to its environmental compliance plan and environmental surcharge in 2009.

Q. What will be the financial impact of this project for EKPC?

A. Based on EKPC's forecasted 2011 revenue from members, the annual financial impact of this project represents an increase of approximately 7 percent in member revenue.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	**CASE NO. 2008-**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

David G. Eames, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

David G Eames

Subscribed and sworn before me on this 11th day of November, 2008.

Peggy S. Griffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)	**CASE NO. 2008-**

DIRECT TESTIMONY OF JULIA J. TUCKER, P.E.
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, business address and occupation.

A. My name is Julia J. Tucker and my business address is East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am Director of Power Supply Planning for EKPC.

Q. Please state your education and professional experience.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Kentucky in 1981. I received my Professional Engineer license from the State of Kentucky (Registration No. 15532) in 1988. I completed 18 hours towards a Masters of Business Administration degree. I have maintained my Continuing Education requirements for my P.E. license. I have been employed in various engineering, planning, and management roles with East Kentucky Power for over 23 years.

Q. Please provide a brief description of your duties at EKPC.

A. I am responsible for all generation / resource planning functions at East Kentucky Power, including generation dispatch, mid-term planning, long term resource planning, contingency planning, load forecasting, load research and demand side planning.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain how EKPC reached the conclusion that the installation of a new Air Quality Control System ("AQCS") at its Cooper Station is the most prudent course of action for EKPC.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Application Exhibit 3, Cooper/Dale Study Report.

Q. Why did EKPC evaluate adding an AQCS at the Cooper Station?

A. As Mr. Marshall references in his Prepared Testimony, EKPC filed a Consent Decree with the Environmental Protection Agency ("EPA") that the Court entered on September 24, 2007. In the Consent Decree, the EPA gave EKPC the option to either install and continuously operate NO_x emission controls and SO_2 emission controls at Cooper Unit 2 by December 31, 2012 and June 30, 2012, respectively, or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012. EKPC has a third option to retire Dale Units 3 and 4 by December 31, 2012 and repower those units by May 31, 2014. As a result of the Consent Decree requirement, EKPC initiated a study to evaluate these options.

Q. What alternatives and scenarios did EKPC consider?

A. EKPC looked at a number of different options in meeting the obligations of the Consent Decree. EKPC considered both wet and dry flue gas desulfurization systems at Cooper Station for Unit 2, or both Units 1 and 2. EKPC also considered repowering Cooper Station with a Circulating Fluidized Bed ("CFB") coal unit. EKPC considered retiring Dale Units 3 and 4, retiring the entire Dale Station, repowering Dale Units 3 and 4 with a Combined Cycle unit (two different configurations), and repowering Dale Units 3 and 4 with a CFB coal unit. Details and results of this study can be found in Application Exhibit 3, Cooper/Dale Study Report. EKPC retained Burns & McDonnell Consulting Engineers ("Burns & McDonnell") to develop the cost estimates and operating characteristics for each of the alternative scenarios considered. EKPC developed market and fuel price outlooks based on a blend of data from multiple sources. EKPC modeled a wide range of market and fuel price scenarios, as well as a range of future environmental cost scenarios. EKPC considered the multiple risks associated with fuel prices and availability, market prices and availability, equipment prices and availability and future environmental compliance costs.

Q. What were the results of EKPC's economic analysis?

A. Based on the economic analysis as shown on Page 39 of Application Exhibit 3, retiring Dale Station, repowering Dale Station and scrubbing Cooper Station were all within a reasonable range of expected financial outcomes. There was less than 10 percent difference in the total twenty-year Net Present Value (NPV) cost of the cases, and no clear choice could be made with only the economic evaluation.

Q. What other factors did EKPC evaluate?

A. In addition to the economic evaluation, EKPC considered various operational and future environmental regulation risks. Operational and power supply concerns are inherent with all of the alternatives considered, and adversely affected some alternatives more than others. Since EKPC is currently in need of additional baseload capacity, retiring Dale Station would exacerbate that problem, making that alternative less viable. Even in today's market, coal prices are more stable and availability less volatile than for natural gas, so the natural gas repowering alternatives were less attractive. However, operational concerns did not clearly distinguish any of the alternatives. As for future environmental regulation risks, EKPC is convinced that additional environmental requirements, such as Best Available Retrofit Technology ("BART"), as described in the Prepared Testimony of John R. Twitchell, will apply to Cooper Station in the future. There are no currently proposed regulations that would require the retirement of Dale Station, or would require EKPC to pursue any of the other alternatives which were evaluated, except for the Cooper Station emission controls. After analyzing these additional concerns, EKPC identified the expected future environmental requirements as the determining factor in the consideration of the alternatives.

Q. What were the overall conclusions of your analysis?

A. Given that economics and operational impacts were similar for all alternatives, the deciding factor became EKPC's conclusion that Cooper Station would have to be modified for further emission control in the future, regardless of the other factors in this study. By installing AQCS on Cooper Unit 2, EKPC will comply with the Consent Decree in a way that will most effectively address the needs of the EKPC system, and that will further future compliance with BART. Based on these conclusions, EKPC decided to pursue installing AQCS facilities at Cooper

Station, and to seek regulatory approvals for the project, which resulted in this request for a Certificate of Public Convenience and Necessity.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER	**)**	
COOPERATIVE, INC. FOR A CERTIFICATE OF	**)**	
PUBLIC CONVENIENCE AND NECESSITY FOR THE	**)**	**CASE NO. 2008-**
CONSTRUCTION OF AN AIR QUALITY CONTROL	**)**	
SYSTEM AT COOPER POWER STATION	**)**	

<u>A F F I D A V I T</u>

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Julia J. Tucker, being duly sworn, states that she has read the foregoing prepared testimony and that she would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of her knowledge, information and belief.

Julia J. Tucker

Subscribed and sworn before me on this 11th day of November, 2008.

Gregory S. Griffin
Notary Public

My Commission expires: December 8, 2009

Exhibit 6

Cooper Station Unit 2 AQCS System
Estimated Annual Operating Costs
November 2008

Annual Expense

Interest	$	19,440,000
Depreciation		18,000,000
Taxes and Insurance		576,000
TIER		8,748,000
O&M		20,777,696
Total	$	67,541,696

COMMONWEALTH OF KENTUCKY

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THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	CASE NO. 2008-

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DIRECT TESTIMONY OF ROBERT M. MARSHALL ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, business address and occupation.

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Q. What is the purpose of your testimony?

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Q. How will this proposed course of action benefit EKPC's members?

A. By installing an AQCS at Cooper Unit 2 and keeping the Dale units in service, EKPC will preserve valuable baseload generation to serve its members. Cooper Station is a proven generation asset for the EKPC system. Continued environmentally compliant operation of this unit has immense value to the EKPC members. Dale Station Units 3 and 4 are proven baseload generation assets to the EKPC system as well. Shutting these units down would cause economic hardships on the EKPC members and create transmission and voltage operational issues on the Central Kentucky transmission system. By preserving proven baseload generating units, EKPC reduces its dependence on outside markets and Kentucky's dependence on out of state generation resources.

Q. What studies did EKPC conduct to determine this course of action?

A. A complete discussion of the studies to determine the need and project alternatives is contained in the Prepared Testimony of Julia J. Tucker, attached as Application Exhibit 9.

Q. Once EKPC chose to construct an AQCS at Cooper Station, how was the proposed technology selected?

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Q. How does EKPC intend to finance the proposed facilities?

A. EKPC's plans to use Rural Utilities Service financing for these facilities are discussed in the Prepared Testimony of David G. Eames, attached as Application Exhibit 8.

Q. Do you believe that the proposed AQCS facilities are the most prudent way for EKPC to meet its identified environmental obligations?

A. Yes. I believe that these facilities are the best way for EKPC to meet that identified need.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	CASE NO. 2008-

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Robert M. Marshall, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

[signature]

Subscribed and sworn before me on this 12th day of November, 2008.

Claudia N. Embs
Notary Public

My Commission expires: March 23, 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	**CASE NO. 2008-**

DIRECT TESTIMONY OF DAVID G. EAMES
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

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Q. Please state your education and professional experience.

A. I received a Bachelor's degree in Engineering from Northeastern University in 1971 and a Master's degree in business Administration in 1976 from the University of Michigan. I am a licensed professional engineer and a certified public accountant in the Commonwealth of Kentucky. In addition, I have attended and participated in several seminars and supplemental training courses over the years. I have been employed by EKPC since January 1979 and have occupied my current position within the EKPC organization since September 1985.

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A. No purchases or commitments for equipment have been made. Although Burns & McDonnell has collected vendor input for project estimate purposes, requests for formal vendor proposals for the design, manufacture and installation of the pollution control equipment must be issued in early 2009.

Q. How will EKPC finance the construction of this facility?

A. EKPC will seek Rural Utilities Service ("RUS") funding for this project.

Q. Is the cost of this project included in EKPC's current rate case?

A. No, the cost of this project is not included in EKPC's application for a general rate increase (Commission Case No. 2008-00409.) However, we believe this project is eligible for recovery in EKPC's environmental surcharge. EKPC will file an application with the Commission for approval of an amendment to its environmental compliance plan and environmental surcharge in 2009.

Q. What will be the financial impact of this project for EKPC?

A. Based on EKPC's forecasted 2011 revenue from members, the annual financial impact of this project represents an increase of approximately 7 percent in member revenue.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	**CASE NO. 2008-**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

David G. Eames, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

David G. Eames

Subscribed and sworn before me on this 11th day of November, 2008.

Peggy S. Diffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION) CASE NO. 2008-

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DIRECT TESTIMONY OF JULIA J. TUCKER, P.E.
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, business address and occupation.

A. My name is Julia J. Tucker and my business address is East Kentucky Power Cooperative (EKPC), 4775 Lexington Road, Winchester, Kentucky 40391. I am Director of Power Supply Planning for EKPC.

Q. Please state your education and professional experience.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Kentucky in 1981. I received my Professional Engineer license from the State of Kentucky (Registration No. 15532) in 1988. I completed 18 hours towards a Masters of Business Administration degree. I have maintained my Continuing Education requirements for my P.E. license. I have been employed in various engineering, planning, and management roles with East Kentucky Power for over 23 years.

Q. Please provide a brief description of your duties at EKPC.

A. I am responsible for all generation / resource planning functions at East Kentucky Power, including generation dispatch, mid-term planning, long term resource planning, contingency planning, load forecasting, load research and demand side planning.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain how EKPC reached the conclusion that the installation of a new Air Quality Control System ("AQCS") at its Cooper Station is the most prudent course of action for EKPC.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Application Exhibit 3, Cooper/Dale Study Report.

Q. Why did EKPC evaluate adding an AQCS at the Cooper Station?

A. As Mr. Marshall references in his Prepared Testimony, EKPC filed a Consent Decree with the Environmental Protection Agency ("EPA") that the Court entered on September 24, 2007. In the Consent Decree, the EPA gave EKPC the option to either install and continuously operate NO_x emission controls and SO_2 emission controls at Cooper Unit 2 by December 31, 2012 and June 30, 2012, respectively, or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012. EKPC has a third option to retire Dale Units 3 and 4 by December 31, 2012 and repower those units by May 31, 2014. As a result of the Consent Decree requirement, EKPC initiated a study to evaluate these options.

Q. What alternatives and scenarios did EKPC consider?

A. EKPC looked at a number of different options in meeting the obligations of the Consent Decree. EKPC considered both wet and dry flue gas desulfurization systems at Cooper Station for Unit 2, or both Units 1 and 2. EKPC also considered repowering Cooper Station with a Circulating Fluidized Bed ("CFB") coal unit. EKPC considered retiring Dale Units 3 and 4, retiring the entire Dale Station, repowering Dale Units 3 and 4 with a Combined Cycle unit (two different configurations), and repowering Dale Units 3 and 4 with a CFB coal unit. Details and results of this study can be found in Application Exhibit 3, Cooper/Dale Study Report. EKPC retained Burns & McDonnell Consulting Engineers ("Burns & McDonnell") to develop the cost estimates and operating characteristics for each of the alternative scenarios considered. EKPC developed market and fuel price outlooks based on a blend of data from multiple sources. EKPC modeled a wide range of market and fuel price scenarios, as well as a range of future environmental cost scenarios. EKPC considered the multiple risks associated with fuel prices and availability, market prices and availability, equipment prices and availability and future environmental compliance costs.

Q. What were the results of EKPC's economic analysis?

A. Based on the economic analysis as shown on Page 39 of Application Exhibit 3, retiring Dale Station, repowering Dale Station and scrubbing Cooper Station were all within a reasonable range of expected financial outcomes. There was less than 10 percent difference in the total twenty-year Net Present Value (NPV) cost of the cases, and no clear choice could be made with only the economic evaluation.

Q. What other factors did EKPC evaluate?

A. In addition to the economic evaluation, EKPC considered various operational and future environmental regulation risks. Operational and power supply concerns are inherent with all of the alternatives considered, and adversely affected some alternatives more than others. Since EKPC is currently in need of additional baseload capacity, retiring Dale Station would exacerbate that problem, making that alternative less viable. Even in today's market, coal prices are more stable and availability less volatile than for natural gas, so the natural gas repowering alternatives were less attractive. However, operational concerns did not clearly distinguish any of the alternatives. As for future environmental regulation risks, EKPC is convinced that additional environmental requirements, such as Best Available Retrofit Technology ("BART"), as described in the Prepared Testimony of John R. Twitchell, will apply to Cooper Station in the future. There are no currently proposed regulations that would require the retirement of Dale Station, or would require EKPC to pursue any of the other alternatives which were evaluated, except for the Cooper Station emission controls. After analyzing these additional concerns, EKPC identified the expected future environmental requirements as the determining factor in the consideration of the alternatives.

Q. What were the overall conclusions of your analysis?

A. Given that economics and operational impacts were similar for all alternatives, the deciding factor became EKPC's conclusion that Cooper Station would have to be modified for further emission control in the future, regardless of the other factors in this study. By installing AQCS on Cooper Unit 2, EKPC will comply with the Consent Decree in a way that will most effectively address the needs of the EKPC system, and that will further future compliance with BART. Based on these conclusions, EKPC decided to pursue installing AQCS facilities at Cooper

Station, and to seek regulatory approvals for the project, which resulted in this request for a Certificate of Public Convenience and Necessity.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Julia J. Tucker, being duly sworn, states that she has read the foregoing prepared testimony and that she would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of her knowledge, information and belief.

Julia J. Tucker

Subscribed and sworn before me on this 11th day of November, 2008.

Gregory S. Griffin
Notary Public

My Commission expires: December 8, 2009

COMMONWEALTH OF KENTUCKY

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DIRECT TESTIMONY OF JOHN R. TWITCHELL
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Q. Please state your name, business address and occupation.

A. My name is John R. Twitchell and my business address is East Kentucky Power Cooperative, Inc., 4775 Lexington Road, Winchester, Kentucky 40392, Senior Vice President, G&T Operations Unit.

Q. Please state your education and professional experience.

A. My undergraduate degree from the University of Florida is a Bachelor of Science in Electrical Engineering with an emphasis in electric energy systems. My graduate degree is a Master of Business Administration from the University of North Florida. I am a licensed professional engineer. I have thirty five years of experience in management, and the planning, permitting, design, construction, operation, and maintenance of electrical utility transmission and generation systems.

Q. Please provide a brief description of your duties at EKPC.

A. I am the Senior Vice President of G & T Operations at EKPC. I am responsible for the permitting, design, construction, operation, environmental compliance, and maintenance of EKPC's transmission system and generation fleet.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to define the selection of the technology involved, the equipment and facilities proposed to be constructed, the capital and operating costs of the proposed facilities, the proposed construction schedule, and the impact of the Air Quality Control System on the fuel requirements for the plant.

Q. Please describe the location and basic scope of the proposed project.

A. The Cooper Air Quality Control System Project ("AQCS") involves adding pollution control equipment to Unit 2 at EKPC's John Sherman Cooper Generating Station ("Cooper Station") located in Burnside, Kentucky (see Application Exhibit 5a, 5b, & 5c). This project more specifically includes the addition of a dry Flue Gas Desulfurization system ("FGD"), a Selective Catalytic Reduction system ("SCR"), and a Pulse Jet Fabric Filter ("Fabric Filter") adjacent to the southeast corner of Cooper Station.

Q. Please identify any public utilities, corporations, or persons with whom the proposed facilities might compete.

A. There are no public utilities, corporations, or persons with whom the proposed facilities at Cooper Station might compete.

Q. How did EKPC determine that the proposed AQCS facilities were needed at Cooper Station?

A. The Prepared Testimony of Julia J. Tucker, Application Exhibit 9, explains the process EKPC used to determine that the installation of the AQCS facilities at Cooper Station is the most prudent alternative for its members.

Q How did EKPC determine which technology to utilize at Cooper Station?

A. EKPC's Engineer for this project, Burns & McDonnell Engineering Company ("Burns & McDonnell"), was charged with screening and assessing environmental control technologies for Cooper Station to meet the requirements of the Consent Decree entered into between EKPC and the Environmental Protection Agency ("Consent Decree"). Burns & McDonnell was tasked with developing pollution control alternatives that would meet three future environmental regulatory scenarios. The first scenario was to meet only the requirements of the Consent Decree. The second scenario was to meet the requirements of the Consent Decree and the anticipated additional environmental requirements for Best Available Retrofit Technology ("BART"). The third scenario was intended to address the most stringent environmental requirements anticipated in the future, Best Available Control Technology ("BACT"). This third alternative was addressed by EKPC to determine if consideration could be reasonably made in the current project to mitigate expenditures that could result from future compliance with yet undetermined emissions thresholds. The result of Burns & McDonnell's assessment is the "Project Scoping Report" attached hereto as Application Exhibit 4.

Q. What are the specific emissions criteria of the Consent Decree for Cooper Station?

A. The specific emissions criteria of the Consent Decree for Cooper Station are listed in Section 1.5.1 of Applicants Exhibit 4, Project Scoping Report by Burns & McDonnell.

Q. What is the origin of BART requirements?

A. Amendments by Congress to the Clean Air Act ("CAA") in 1977 set forth a program to protect visibility in sensitive areas of the United States, including Mammoth Cave National Park. Further amendments to the CAA in 1990 called on the EPA to issue regional haze rules to address fine particle pollution that impairs visibility over large regions. As part of this program, states are required to submit State Implementation Plans ("SIPs") to EPA that set out each state's plan for complying with EPA's regional haze rule. The development of the SIP includes an assessment and recommendation of Best Available Retrofit Technology ("BART") for specific sources of particulate matter ("PM") pollution.

Q. What is the origin and current status of CAIR requirements?

A. The Clean Air Interstate Rule ("CAIR"), Final Rule, appeared in the Federal Register on May 12, 2005 and established federally required emissions thresholds for SO_x, NO_x, and PM. CAIR was vacated by the D.C. Circuit Court of Appeals on July 11, 2008. Parties in the case have moved for a rehearing of the decision and the D.C. Circuit asked for additional briefing on whether to stay the decision until EPA issued a replacement rule on October 21, 2008. Most industry experts believe that a replacement for CAIR will be re-established in some form in the near future.

Q. How are BART and CAIR related?

A. In many ways BART can be viewed as a subset of CAIR under the May 12, 2005 Final Rule. In Kentucky, since CAIR stated lower emission requirements than BART for SO_x and NO_x, BART was applied only to PM emissions for those units that were built and completed between 1962 and1977. EKPC has 4 units that meet that criteria for BART (Spurlock 1 and 2, Cooper 1 and 2).

Q. How do BART and CAIR affect Cooper Unit 2?

A. EKPC entered into the Consent Decree in September 2007, which required EKPC to install AQCS facilities for Cooper 2 or retire units at Dale Station.

Prior to the Consent Decree, Kentucky Division of Air Quality ("KDAQ") had required EKPC to model the BART-eligible units and submit a unit specific strategy for EKPC to meet the regulations under BART for particulate emissions ("PM") as proposed to the EPA in the Kentucky SIP, submitted in June 2008. For Cooper Station, Kentucky's SIP included a Wet Flue Gas Desulfurization ("Wet FGD") process and a Wet Electrostatic Precipitator ("Wet ESP") as the appropriate strategy for BART. CAIR was more stringent than BART for NO_x and SO_x emissions, so EKPC did not have to model SO_x and NO_x emissions for BART in the Kentucky SIP.

Although CAIR was vacated by the D.C. Circuit on July 11, 2008, that action had no impact on the environmental measures required by the Consent Decree. The Kentucky SIP was also not modified when CAIR was vacated, and currently reflects the former CAIR requirements for SO_x and NO_x.

Q. How did BART and CAIR requirements impact EKPC's decision about the technology selection for the AQCS at Cooper Station?

A As previously discussed, in order to prudently consider current and anticipated environmental requirements, the second scenario in EKPC's evaluation of the technology for the AQCS at Cooper Station included the requirements of the Consent Decree, plus BART and CAIR. EKPC's selected system, if approved and implemented, will meet or exceed the requirements of the Consent Decree, BART and CAIR.

Q. What is BACT and how does it affect new and existing generating plants?

A. The origin of BACT is a rule and memorandum issued by EPA in 1989, which revised the New Source Review ("NSR") program. It defines BACT as the result of a unit specific, case-by-case evaluation to determine the best technology that can economically deliver the lowest affordable emissions for the pollutants regulated under the Clean Air Act. The status of the definition and intent of BACT has not changed since its inception.

Q. How was BACT evaluated as part of EKPC's selection of technology for the Cooper Station AQCS project?

A. EKPC recognizes BACT is advanced by each new technology that achieves lower emission levels than have been previously attained. The third environmental scenario considered BACT in the project scope. The proposed AQCS for Cooper Station Unit 2, if approved and implemented, will meet or exceed the Consent Decree requirements, BART and former CAIR requirements, and is consistent with the BACT emissions for new pulverized coal units.

Q. What opacity standards apply to the Cooper Unit 2 and how is opacity measured?

A. KDAQ issued a Title V air permit for Cooper Station on January 8, 2007 that specifically states that the units must meet 0.23 lbs PM emissions / mmBtu. The Title V air permit requires EKPC to monitor opacity by use of continuous opacity monitors ("COMs"). Because the dry process proposed does not emit a wet plume, opacity measurement can be effectively accomplished at Cooper as it is now with COMS.

Q. What alternatives were considered by Burns & McDonnell in its Project Scoping Report?

A. Two scrubbing processes currently operational in the electric generating industry are capable of meeting the pollutant removal requirements of the Consent Decree. The original pollution control strategy anticipated for Cooper Station (as part of the Cooper/Dale Study Report, Application Exhibit 3, and as identified in the Kentucky Regional Haze State Implementation Plan as BART) was the installation of a Wet Flue Gas Desulfurization process ("Wet FGD") and a Wet Electrostatic Precipitator ("Wet ESP"). In early discussions with Burns & McDonnell, Dry Circulating Fluidized Bed ("CFB") FGDs were introduced as a possible option for the AQCS at Cooper Station, due to their potential for equivalent or better emission control performance and reduced capital cost. Additionally, this technology is attractive to EKPC because of its compatibility with units similar to Cooper Unit 2, reduced complexity, and reduced equipment footprint. Further investigation by Burns & McDonnell evaluated the relative emission reduction performance of the two technologies. Additionally, an economic evaluation compared the costs of the two scrubbing technologies for this initial screening of wet versus dry technologies.

The technical assessment is documented in a report entitled "Information in Support of Demonstration of Equivalency of CFB Dry FGD Technology to Wet FGD/Wet ESP Technology for Determination of Best Available Retrofit Technology for Cooper Station Units 1 and 2", attached as JRT Exhibit 1. In that report, Burns & McDonnell concludes, "...from an emissions control perspective, the CFB Dry FGD technology is clearly equivalent to, or better than, the 'Wet FGD/Wet ESP' technology combination."

Q. Please describe the proposed CFB Dry FGD technology.

A. The proposed CFB Dry FGD process includes a circulating fluidized bed dry scrubber system that uses water and hydrated lime to capture the sulfur constituents of the flue gas. This process creates dry solid particles that are then collected in a Fabric Filter. The collected solids are recycled to the circulating fluidized bed absorber to maximize pollutant removal and lime utilization. The process avoids the costs and maintenance of handling the limestone water slurry found in a Wet FGD, and is relatively compact. The CFB Dry FGD process is depicted in Section 2 of Application Exhibit 4. Although only CFB Dry FGD technology is proposed as part of the initial project scope, other Dry FGD technologies will also be considered, provided that manufacturer guarantees made for acceptable performance can be obtained.

Q. Is the CFB Dry FGD technology proven?

A. Yes. A paper was presented at the Power Plant Air Pollutant Control Mega Symposium in August 2008 in Baltimore, MD describing the past year's operation of a CFB Dry FGD installation at AES's Greenidge Plant in Dresden, NY. The Greenidge Multi-Pollutant Control Project was conducted as part of the U.S. Department of Energy's Power Plant Improvement Initiative to demonstrate technologies that are well suited for effective emissions reduction at smaller coal-fired units. This paper is incorporated into the Burns & McDonnell report attached hereto as JRT Exhibit 1, and includes assessments of both the environmental and economic performance of the installation during its first year of commercial operation.

The demonstrated removal efficiencies for SO_x at the Greenidge facility meet the requirements of EKPC's Consent Decree. It is well established that particulate matter is very effectively controlled by a Fabric Filter, and although not a requirement of the Consent Decree, high levels of mercury removal were also demonstrated with this technology. Also, because the process is dry, Sulfuric Acid Mist ("SAM") is less of an issue than with Wet FGD systems.

Q. What are some of the specific benefits of Dry FGD technology for Cooper Station?

A. In general, Dry FGD processes eliminate the need for major water/wastewater equipment capital expenditures and associated operations and maintenance costs, and permit compliance issues. The karst geology at Cooper Station presents challenges in this regard for controlling water runoff and managing the slurry drying process. A Dry FGD will not require a new stack, whereas a new 400 foot stack would be required for a Wet FGD. A Dry FGD will be less complex and easier to construct, which increases the likelihood of meeting the completion schedule in the Consent Decree.

The result of the Burns & McDonnell cost analysis demonstrated that the CFB Dry FGD provided EKPC with initial capital investment savings of $127 million and a 20-year net present value savings of $21 million as compared to the Wet FGD/Wet ESP process.

Q. Were any other technology alternatives screened by Burns & McDonnell?

A. Burns & McDonnell evaluated a third technology option that was a hybrid of the first two alternatives. This alternative included a Wet FGD, but used the existing Electrostatic Precipitator at Cooper Station instead of a new Wet ESP. However, the hybrid alternative would require the same construction of a new stack and the slurry and water systems as the Wet FGD/Wet ESP alternative. Recent installations of the CFB Dry FGD technology have demonstrated that the process will perform better than the Wet FGD/Wet ESP and much better than a Wet FGD combined with the existing ESP at Cooper Station (the hybrid alternative) for the reduction of Particulate Matter and Mercury emissions because of the incorporation of the Fabric Filter.

Q. How did these technologies compare on an economic basis?

A. When compared to the hybrid alternative, the capital investment savings for the CFB Dry FGD process was $75 million, but the net present worth analysis indicated a $37 million savings for the hybrid alternative over a 20 year evaluation period. The net present worth savings advantage for the hybrid alternative over the 20 year evaluation period is relatively uncertain because it is primarily made up of end of period projected fuel and reagent costs that are highly unpredictable. These factors and the large near term capital savings of the CFB Dry FGD led to the elimination of the hybrid alternative from further consideration.

Q. Which of the three design scenarios for the Cooper Station AQCS project, that you discussed earlier in this testimony, will the CFB Dry FGD technology address?

A. After evaluating the CFB Dry FGD technology, EKPC determined that it is not only the best technology to meet the requirements of the Consent Decree exclusively, it can also effectively perform in compliance for all three of the design scenarios.

Q. Does EKPC require environmental approvals for the use of the CFB Dry FGD technology at Cooper Station?

A. Yes. EKPC is seeking a determination from the Kentucky Division of Air Quality that the CFB Dry FGD system represents "equivalent technology" to the Wet FGD system which was originally designated as BART in the Kentucky SIP. If CFB Dry FGD technology cannot be used, then a new stack for Cooper Station and a "polishing scrubber" for Cooper Unit 2 may be required.

Q. What air pollution control equipment currently exists at Cooper Station?

A. Cooper Station currently has particulate control emission equipment in operation, which consists of a mechanical dust collector and electrostatic precipitator ("ESP") on Unit 1 and an ESP on Unit 2.

Q. Does the proposed project duplicate processes or systems already in place?

A. No. The current pollution control equipment at Cooper Station cannot meet, or be modified to meet, the emissions requirements of the Consent Decree.

Q. Will the proposed AQCS facilities for Cooper Station meet future EPA and other environmental requirements?

A. Yes. The proposed AQCS for Cooper Unit 2 will meet the Consent Decree, BART, and Hg Maximum Achievable Control Technology (MACT) requirements, as best as EKPC can predict them today.

Q. Will the Cooper Station AQCS Project require that equipment changes be made to the existing Cooper Station facilities?

A. Yes. The addition of the new AQCS facilities will require upgrades or equipment changes to Cooper Station's control system, electrical supply system, ash handling facilities, boiler, waste disposal system, Continuous Emissions Monitoring System (CEMS), and the replacement of fans and airheaters. These changes and upgrades are more specifically outlined in Application Exhibit 4. Additionally, the Project scoping process was intended to carefully consider the ultimate site arrangement needed for potential future facilities like unit train coal handling capability for Illinois Basin coal or the addition of an SCR and FGD for Unit 1. The development of an ultimate site arrangement reserves space on the site and provides preliminary considerations for systems and features that can be selectively implemented at a later date, based on future environmental requirements and/or economics.

Q. Are there any other pending regulations that would require further reduction of SO_x emissions at Cooper Station?

A. EKPC does not know of any other pending EPA or State of Kentucky regulations that apply at this time.

Q. What provisions have been made to implement additional air pollution controls for Cooper Unit 1, if it should become necessary?

A. Provisions have been made to leave space for the installation of AQCS equipment specifically designed for Cooper Unit 1. The stack will remain common to both units.

Q. How will this project impact the existing net generating capacity at Cooper Station?

A. The new AQCS is estimated to use 7.7 MW of the available output at Cooper. EKPC is investigating upgrades to the boilers and turbines to improve efficiencies and increase the electrical output to help offset this parasitic power loss. These upgrade options will be evaluated on an economic stand-alone basis.

Q. Does this project impact EKPC's transmission system?

A. No. EKPC performed a transmission analysis to evaluate impacts to the transmission system for the addition of this equipment and other associated changes to Cooper Station. The summary report (attached as JRT Exhibit 2) indicates that, based on proposed project scope, no transmission additions or modifications are needed.

Q. What is the schedule for the construction of the Cooper AQCS Project?

A. Construction is scheduled to commence in June 2010 and commercial operation is required in June 2012 to comply with the Consent Decree. Although the Consent Decree requirements state December 31, 2012 as the compliance date for SCR operation, EKPC will pursue the commercial operation of both the FGD and SCR by June 2012 in order to implement an efficient and orderly construction plan. Bids for major pieces of equipment are scheduled to be solicited in early 2009 with contract awards in the Spring of 2009. The design and manufacture of the larger pieces of equipment will take approximately one year.

Q. What are the estimated costs for the AQCS installation at Cooper Station?

A. Based on scope development and preliminary layout, the installed cost for the project is estimated to be $324 million, which includes an Estimate Accuracy Contingency of 15% and a Project Definition Contingency of 10%, per the Burns & McDonnell "Preliminary Cost Estimate" on page 5-6 of Application Exhibit 4.

Q. For comparison purposes, what are the installed costs of the Spurlock Unit 1 & 2 scrubbers?

A. The Spurlock Unit 1 Scrubber is estimated to cost $173 million and is on schedule for commercial operation in April of 2009. The Spurlock Unit 2 Scrubber is estimated to cost $207 million and is on schedule for commercial operation in January of 2009. These projects did not include SCR's or Fabric Filters.

Q. What are the estimated annual costs of operation of the Cooper Unit 2 AQCS facilities?

A. The estimated annual cost is approximately $68 million as indicated in the attached Application Exhibit 6.

Q. How did EKPC incorporate fuel considerations into this project?

A. EKPC conducted an initial screening to identify fuels to use for development of the preliminary design of the AQCS project. The details of this process are more specifically outlined in an EKPC internal document entitled "Cooper Retrofit Project – Fuels Screening Summary" attached as JRT Exhibit 3.

The first broad selection of fuel candidates was based on available markets and incorporated 19 different coal types. A narrowing process was then undertaken to identify the largest variety of coals that could be used both practically and cost effectively in the modified generating plant. EKPC worked with Burns & McDonnell to group the fuels, and representative coals from each group were used by the Cooper Station boiler manufacturer (Babcock & Wilcox) to evaluate impacts to the existing equipment. A "design coal" was identified to use as an outer limit, or worst case for the preliminary engineering design of the pollution control process and equipment. This approach is based on the premise that if the new equipment and processes work effectively with the "design" or representative coals, the other economically viable fuels and fuel mix alternatives will also be acceptable from both the operational and environmental performance perspectives. Although the "design" coal may never be actually used for production at the Cooper Station, it represents the practical limits of the equipment and preliminary process design for fuel use.

Q. Please describe the different coals that were used in the Cooper AQCS evaluation.

A. The following table lists the 19 coal types that were identified for evaluation. Energy Ventures Analysis ("EVA") provided projected coal prices for the 19 coal types in $/MMBtu through 2030 (FOB mine). EKPC estimated transportation costs to Cooper Station using a combination of historical transportation costs combined with projections based on available market information to determine a delivered cost.

Economic Analysis				
Coal Type	**FOB Point**	**Btu/lb**	**#SO2/MMBtu**	**Ash (%)**
CAPP -Raw	Truck	9300	2.2	32
ILB-WK	Green Rvr	10500	7	20
CAPP-Manchester	Truck	12000	4.5	11
ILB-WK	Green Rvr	11500	6	10
CAPP-Hazard	Truck	12000	4.5	11
CAPP-Manchester	Truck	12000	2.8	11
CAPP-Hazard	Truck	12000	2.8	11
NAPP-Ohio Strip	Ohio Rvr	11500	7	10
CAPP-Hazard	Truck	12000	2.2	11
CAPP-Hazard	Truck	12000	1.6	11
CAPP-Hazard	Truck	12000	1.2	11
NAPP-Pitts VH	Ohio Rvr	12500	6	10
CAPP-Pike-Uncrushed	Truck	12000	2.8	11
CAPP-Pike-Uncrushed	Truck	12000	2.2	11
CAPP-Pike-Uncrushed	Truck	12000	1.6	11
NAPP-Pitts Raw	Ohio Rvr	9500	7.5	30
CAPP-Pike-Uncrushed	Truck	12000	1.2	11
NAPP-Pitt HS	Mon Rvr	13000	3.8	8
PRB	Rail	8800	0.8	5

Three of the coal types above were eliminated because they failed to meet both the Btu/lb and Ash specification for Cooper Station and a fourth was eliminated due to significantly higher transportation costs. Specific coals were identified for the remaining groups and they are listed in the following table with an asterisk identifying the representative coals in each group.

Performance Analysis	
Group 1	**Illinois Basin Group** Williamson - Illinois #6 * James River - Indiana #5 Highland #9
Group 2	**Central Appalachian Group A (High Sulfur)** * Middle 8 Hazard Hazard 8 Split 2 Trinity/Little Elk Mining
Group 3	**Central Appalachian Group B (Mid-Range Sulfur)** * Sample S-667 Sample S-671 Sample S-673 Sample S-674-1
Group 4	**Central Appalachian Group C (Low Sulfur)** Dale Gatliff 2116 * Dale Trinity 2117
Group 5	**Northern Appalachian Group** Daron #8 * Daron #9
Group 6	**Powder River Basin**

Q. Did the fuel choices affect the final decision of the chosen technology?

A. No. Fuel was also not a limiting factor in choosing the pollution control technology for preliminary design. Modeling and analysis of predicted equipment performance based on Sulfur content, Ash content, Btu/lb, cost, and fusion temperature indicate that the representative coals are reasonable for consideration in the processes and equipment evaluated for preliminary design. There were no significant performance issues identified to cause elimination of any of the fuels from consideration for use at Cooper Station.

Q. What types of coals are currently used to fuel Cooper Station Units 1 & 2?

A. Cooper Station is currently burning bituminous coal from various seams in the Central Appalachian ("CAPP") coal basin in both of its generating units. The calorific value for this coal will range from 11,000 to 12,500 BTU/lb with an Ash range of 8 to 20% and a Sulfur content of less than 3%. The coals are blended to comply with Cooper Station's Title V air permit.

Q. What type(s) of coal will Cooper Station Unit 2 be able to burn once the AQCS projct is completed?

A. Cooper Station Unit 2 should be able to burn CAPP, Northern Appalachian ("NAPP"), and Illinois Basin ("ILB") coals after the AQCS project is complete providing that the boiler can handle the low fusion coals. The detailed design phase of the project will address this issue.

Q. How will Cooper Station fuel costs change as a result of this modification to the plant?

A. The AQCS facilities will allow EKPC to meet environmental standards and use higher Sulfur coals. EKPC expects the cost of coal on a Btu basis for Unit 2 to decline. EKPC studies show that if Illinois Basin coal can be used, the gross fuel cost savings for Cooper Station Unit 2 when comparing the Illinois Basin coal and the current Central Appalachian coal over a 10 year period (2012 – 2022) are projected to be over $12 million.

Q. Do you believe that the proposed AQCS facilities at Cooper Station are the best and most effective alternative for meeting the identified environmental control needs of the EKPC system?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF AN AIR QUALITY CONTROL SYSTEM AT COOPER POWER STATION	)))))	**CASE NO. 2008-**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

John R. Twitchell, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

John R Twitchell

Subscribed and sworn before me on this 12th day of November, 2008.

Peggy S. Duffin
Notary Public

My Commission expires: December 8, 2009

Information in Support of Demonstration of Equivalency of CFB Dry FGD Technology to Wet FGD / Wet ESP Technology for Determination of Best Available Retrofit Technology for Cooper Station Units 1 and 2

Prepared for
East Kentucky Power Cooperative

Prepared by
Burns & McDonnell Engineering Company
September 16, 2008
Project 50198

Table of Contents

1.0 PURPOSE

This report presents information in support of a demonstration that the use of the circulating fluidized bed dry flue gas desulfurization (CFB Dry FGD) technology for control of SO_2, filterable particulate and condensable particulate (e.g., H_2SO_4) is equivalent to or better than the technology identified as Best Available Retrofit Technology (BART) for Cooper Station Units 1 and Unit 2 in the "Regional Haze State Implementation Plan for Kentucky's Class I Area" (KY RH SIP).

The KY RH SIP was based on information from the "BART Analysis for PM Emissions" submitted to KYDAQ on behalf of East Kentucky Power Cooperative (EKPC) and included in Appendix L.11 of the KY RH SIP. This report also presents information to show that the "BART Analysis for PM Emissions" for Cooper Station improperly excluded consideration of CFB Dry FGD and misrepresented the requirements of the Consent Decree (CD) with regard to the latitude that EKPC has under the CD in the selection of control technologies for CD compliance. The result of this misrepresentation was that the "BART Determination" as established by KYDAQ for Cooper Station in the KY RH SIP is unduly restrictive with regard to the control technologies identified as BART. Finally, this report provides information that KYDAQ can use to consider appropriate modifications to the control technology requirements for Cooper as currently reflected in the KY RH SIP.

2.0 THE COOPER STATION BART ANALYSIS IN KYDAQ's REGIONAL HAZE SIP

As described in the KY RH SIP, the Cooper Station Unit 1 and Unit 2 are subject to BART. However, due to the provisions of EPA's Clean Air Interstate Rule (CAIR), the determination of BART was required for particulate matter (PM) emissions only. The BART determination for PM that is included in the KY RH SIP at Section 7.5.3 was based on the "BART Analysis for PM Emissions" as submitted to KYDAQ on behalf of EKPC.

2.1 Summary of BART Determination

The BART Determination for Cooper Station Units 1 and 2 is expressed in the KY RH SIP as follows:

> *These five sources are considered to be "subject to BART" and were required to submit BART determination modeling containing their evaluation of potential BART control options and proposed BART determinations. Each of these sources has agreed to install emission controls to address inorganic condensible particulate emissions (SO_3/H_2SO_4), which is causing the sources to be subject to BART. The BART determination resulting controls are provided in the Table 7.5.3-1 that follows and they were taken to public hearing concurrent with the public hearing on Kentucky's Regional Haze SIP. Table 7.5.3-2 that follows, in addition to the emission controls, provides the source's BART emission limits and timeframes for compliance. Applicable*

BART controls and emission limits will be incorporated into the sources' Title V permit as appropriate or upon renewal. [KY RH SIP, pg 62].

These "resulting controls" as tabulated for Cooper Unit 1 and Unit 2 are stated as follows:

EKPC per a consent decree and for BART will install a wet FGD and wet ESP at EKPC Cooper Units 1 and 2 that will address condensible particulate emissions and other visibility impairing pollutants. [KY RH SIP, pg 63].

The "emission limit" as tabulated for Cooper Units 1 and 2 is stated as follows:

A 07/02/07 EKPC consent decree provides a filterable PM emission rate of 0.030 lb/MMBTU, which was utilized to demonstrate modeled visibility improvement. [KY RH SIP, pg 65].

It should be noted that the BART emission limit is expressed only in terms of filterable PM. For modeling purposes, the inorganic condensable PM (H_2SO_4) emission value assumed in the regional haze impact analysis for the Cooper Station after installation of BART controls was 0.018 lb/mmBtu.

2.2 Technologies Considered in "BART Analysis for PM Emissions"

The "BART Analysis for PM Emissions" prepared for EKPC [included as pages 14 through 19 in Appendix L of the KY RH SIP] purported to follow a 5-step process. Step 1 was to identify all available retrofit technologies. Only two technologies were identified in Step 1 – electrostatic precipitation (ESP) and fabric filtration. Neither technology was eliminated in Step 2. However, later, in Step 3, which was to "evaluate control effectiveness of remaining control technologies", a third control technology was inserted. This alternative was listed as "ESP with WFGD (wet flue gas desulfurization)". The controlled emissions from this combination of technologies was selected to provide the lowest total PM emission, and no other technologies were carried forward in the evaluation.

2.3 Technologies Not Considered in "BART Analysis for PM Emissions"

The evaluation of control effectiveness in Step 3 of the analysis was based on the combined effect of a WFGD and an ESP on emissions of PM as determined using PM speciation spreadsheets developed by the National Park Service (NPS) for this combination. The analysis did not consider the combined effect of FGD and fabric filtration, despite the fact that the NPS also has provided a spreadsheet for this combination.

It is inequitable to consider the effect of FGD on one particulate control technology alternative but not another. It appears there was a belief that the NPS spreadsheet for the combination of "FGD + ESP" is based on the use of a wet ESP following a wet FGD, when in fact it is based on a dry ESP followed by a wet FGD. (The NPS spreadsheets are based on information provided in EPA's AP-42 Tables 1.1-5 and 1.1-6, which clearly do not include or reference any data from plants equipped with wet ESPs). This approach resulted in the elimination of fabric filtration

from further consideration despite the fact that the analysis correctly characterized fabric filtration as having a significantly greater degree of control for filterable PM than does an ESP. Given that it is appropriate to consider the combined effect of FGD processes and particulate control equipment on total (filterable plus condensable) PM emissions, the failure to consider in the BART analysis available retrofit technologies that combine FGD and fabric filtration is a significant deficiency in the "BART Analysis for PM Emissions" for Cooper.
For coal-fired boilers, the greatest contributor to condensable PM is sulfuric acid (H_2SO_4). It is well known that of the two principal types (wet and dry) of FGD processes, the dry FGD processes exhibit substantially greater control capability for H_2SO_4 than do the wet processes. Therefore, it would have been appropriate to consider the combination of dry FGD and fabric filtration in the BART analysis for PM.

2.4 Misrepresentation of Consent Decree Requirements

One reason that other alternatives for PM control were not considered in the BART Analysis is the misinterpretation of the requirements of the Consent Decree in the case of *United States of America v. East Kentucky Power Cooperative*, No. 04-34-KSF, as they relate to the type of control equipment to be installed at Cooper Station. Step 4 of the BART Analysis states:

> *EKPC will retrofit its BART-eligible units with WFGD for SO_2 control and wet ESPs for PM control pursuant to a draft EPA consent decree mandating reductions in SO_2, NO_x and PM emissions from several generating units, including the BART-eligible units at the Spurlock and Cooper facilities.*

This is incorrect in several respects. First, the CD does not cover SO_2 or NO_x emission rates from Cooper Unit 1. Second, the CD does not dictate the type of FGD process that is to be used at Cooper Unit 2. Third, the CD does not require the installation of wet ESPs at Cooper.

It appears that this misunderstanding and misstatement of the CD requirements has passed through the KY RH SIP development process and unduly influenced the identification of specific technologies (wet FGD and wet ESP) as being the "top control" and "BART" for Cooper Units 1 and 2. As described in the remainder of this report, proper unrestricted consideration of the available dry FGD process known as CFB Dry FGD would have resulted in a determination that it is at least equivalent to, if not better than, the combination of wet FGD and wet ESP that has been established as BART in the KY RH SIP.

3.0 CONSIDERATIONS FOR WET FGD FOLLOWED BY WET ESP

3.1 Commercial Status and Experience on Coal-fired Utility Boilers

In is unquestionably true that wet FGD is the most commonly used technology for control of SO_2 emissions from coal-fired utility boilers, both in the U.S. and world wide. Likewise, it is true that wet ESP technology is well developed, especially for application on industrial processes. However, the combination of wet FGD and wet ESP on coal-fired boilers is extremely rare. In the U.S. there are currently only two coal-fired electric utility boilers for which this technology combination is in full-scale operation. These are Excel Energy's Sherburne County Units 1 and 2, which fire low-sulfur coal from the Powder River Basin (PRB). These units each have 12 wet ESP modules, and can achieve reliability only by sequencing the modules off-line for routine maintenance. EKPC has installed a wet ESP at its Spurlock Unit 2 in accordance with Appendix A of the CD, but this device is not operational as of this writing. Three proposed new coal-fired utility boilers in the U.S. have recently received permits based on the use of wet ESPs for H_2SO_4 control, including Trimble County Unit 2 in Kentucky, but none of these are yet operational.

3.2 SO_2 Control Capability

Wet FGD technologies offer the potential for SO_2 removal efficiencies at or above 95 percent. Historically, wet FGD systems have typically been identified as best available control technology (BACT) in permits for new U.S. power plants firing high-sulfur coal. EPA has addressed the issue of control capability for wet FGD systems in the revisions to the new source performance standards for electric utility steam generating units that were promulgated February 27, 2006:

> *EPA has concluded that 98 percent control is possible with certain control and boiler configurations under ideal conditions. The amended SO_2 standard is based on a 30-day average that includes the variability that occurs from non-ideal operating conditions...*
> *The amended SO_2 standard is either 1.4 lb/MWh or 95 percent reduction on a 30-day rolling average.* [71 FR 9870-9871]

3.3 H_2SO_4 Control Capability

The capability of wet FGD systems to control condensable particulate (H_2SO_4) is generally stated to be in the range of 50% (+/- 20%). By adding a wet ESP downstream of the wet FGD, it is possible to achieve improved control of H_2SO_4. Recent BACT determinations for new coal-fired boilers proposed with wet FGD followed by wet ESP have included H_2SO_4 emission limits ranging from 0.004 lb/mmBtu to 0.01 lb/mmBtu. As noted previously, none of these units is in operation, so the ability of these systems to achieve these permitted emission limits has not yet been demonstrated.

3.4 Particulate Control Capability

The KY RH SIP establishes the Cooper Station Unit 1 and 2 BART emission limit for filterable PM as 0.03 lb/mmBtu. This is substantially below the current filterable PM emission from the existing ESPs, which has been reported to be in the range of 0.09 to 0.15 lb/mmBtu. Wet FGD technologies have the capability to provide moderate levels of particulate emission control as a co-benefit of the process that leads to the capture of SO_2. The degree of particulate control achieved will depend on the absorber type used and the particle size distribution of the incoming fly ash. It is possible that the retrofit of a wet FGD absorber alone will be able to achieve the BART emission limit. However, wet FGD systems also generate particulate emissions due to the carryover of mist droplets from the process. The inclusion of a wet ESP for H_2SO_4 control will enhance the ability of the emission control system to control filterable PM emissions. Of the three new unit permits cited previously that have included wet ESPs as BACT for H_2SO_4 emissions, two included filterable PM emission limits of 0.015 lb/mmBtu. The other permit did not include an emission limit for filterable PM.

3.5 Mercury Control Capability

Mercury control at Cooper Station is not required by BART or the CD. However, for comparative purposes it is useful to examine expected and demonstrated control capabilities for mercury. Wet FGD systems are capable of achieving 80 to 90 percent removal of oxidized forms of mercury, which are soluble in water. However, elemental mercury, which is not water soluble, cannot be removed by wet FGD systems. Also, testing has shown that some of the oxidized mercury captured in a wet FGD system may be chemically reduced to the elemental form and re-emitted into the flue gas leaving the wet FGD. This means that the overall removal efficiency for mercury by wet FGD systems is a function of the degree of oxidation of mercury in the flue gas and the extent to which the re-emission phenomenon occurs. Mercury oxidation is affected by the halogen content of the coal fired and by the catalyst used in a selective catalytic reduction (SCR) system for NOx control. For compliance with the CD, Cooper Unit 2 will be retrofitted with an SCR system, whereas Unit 1 is not required to retrofit SCR. Consol Energy, working under contract to U.S. DOE NETL, conducted an extensive multi-year study of mercury removal at coal-fired power plants fitted with SCR and FGD, including wet FGD and lime spray dryer FGD. The conclusions of the study were stated as follows:

> *The results show that the SCR-FGD combination can remove a substantial fraction of mercury from flue gas. The coal-to-stack mercury removals ranged from 65% to 97% for the units with SCR and from 53% to 87% for the units without SCR. There was no indication that any type of FGD system was better at mercury removal than others.* [DE-FC26-02NT41589 Final Report, April 2006]

4.0 CONSIDERATIONS FOR CFB DRY FGD

4.1 Commercial Status and Experience on Coal-Fired Utility Boilers

CFB Dry FGD is not a new technology, and it has established an extensive experience base internationally over the past 15 to 20 years, including application to coal-fired boilers as large as 350 MW. It is described in the November 2000 U.S. EPA report "Controlling SO_2 Emissions: A Review of Technologies"(EPA/600/R-00/093), which is cited (see 70 FR 39164) as a recommended resource for identification of control alternatives for consideration as BART in the EPA's "Guidelines for BART Determinations Under the Regional Haze Rule" (40 CFR 51, Appendix Y). However, until recently it has been applied in the U.S. to only a few small (<100 MW) coal-fired utility boilers.

Recently (National Lime Association, "Flue Gas Desulfurization Technology Evaluation: Dry Lime vs. Wet Limestone FGD" March 2007) the CFB Dry FGD technology was reported to be offered in the U.S. by three different vendors:

- Allied Environmental Solutions, Inc. (formerly Lurgi) "CDS-FGD"
- Austrian Energy and Environment, % Babcock Power Environmental; "Turbosorp® FGD"
- Wulff Deutschland GmbH, % Nooter/Eriksen; "Graf/Wulff."

A telephone survey conducted by Burns & McDonnell in September 2008 confirmed that all three of these vendors would offer and guarantee their technology for the Cooper Station FGD retrofit project if given the opportunity.

The first U.S. installation of the Turbosorp CFB Dry FGD by Babcock Power was completed in 2007 at the 107 MW AES Greenidge Unit 4, and favorable results of the first year of operation have been reported in August 2008 at the Power Plant Air Pollutant Control "Mega" Symposium (refer to attached technical paper). Babcock Power is currently working on several additional U.S. retrofit projects that will supply CFB Dry FGD (Turbosorp) technology, including the 238 MW Deerhaven Unit 2 of Gainesville (Florida) Regional Utilities.

Allied Environmental Solutions, which has CFB Dry FGD experience in the U.S. dating back to 1995, is supplying CFB Dry FGD systems for new utility pulverized coal-fired boilers that are currently under construction in Springfield, Missouri (275 MW) and Hastings, Nebraska (220 MW). In addition, Allied is supplying their technology for use as a "polishing" FGD downstream of CFB utility boilers currently under construction in Louisiana and Texas.

Nooter/Eriksen is supplying the CFB Dry FGD technology for the 385 MW Dry Fork Power Station which is currently under construction near Gillette, Wyoming. This will be the largest CFB Dry FGD system in the U.S.

4.2 SO_2 Control Capability

With regard to the control capability of CFB Dry FGD, the previously cited National Lime Association report stated, that "SO_2 removal guarantees of 95-98% are available from the system suppliers identified". In order to obtain an indication of the specific guarantees that would be offered for the coals that are expected to be fired at Cooper Station after the FGD retrofits that will be required for compliance with the CD and BART, Burns & McDonnell requested specific statements from Allied Environmental Solutions and Babcock Power Environmental as to the SO_2 control levels that would be offered as guarantees. Copies of their responses are attached to this report. The results are as follows:

- Allied Environmental Solutions would guarantee 99% SO_2 removal down to an emission rate not less than 0.022 lb/mmBtu.
- Babcock Power Environmental would guarantee 98% SO_2 removal throughout the fuel sulfur range from 4.0 lbs SO_2/mmBtu to 7.0 lbs SO_2/mmBtu.

4.3 H_2SO_4 Control Capability

Both Allied Environmental Solutions and Babcock Power Environmental also provided an indication of the level of H_2SO_4 control that they would guarantee for the Cooper Station coals.

- Allied Environmental Solutions would guarantee 99% H_2SO_4 removal down to an emission rate not less than 1 ppm dry at 3% O_2, which they indicated was equivalent to approximately 0.003 to 0.0035 lb/mmBtu.
- Babcock Power Environmental would guarantee an H_2SO_4 emission level at the outlet of their system of 0.005 lb/mmBtu.

The attached paper reporting the results from the AES Greenidge plant confirms that in 26 tests conducted during the first year of system operation, the Babcock Power Turbosorp system achieved stack SO_3 emissions below 1 ppmvd at 3% O_2.

4.4 Particulate Control Capability

The CFB Dry FGD system includes a fabric filter baghouse downstream of the fluidized bed absorber. As such, it can be expected that the capability for control of filterable PM emissions would be excellent. Allied Environmental Solutions indicated that an emissions guarantee of 0.012 lb/mmBtu would be offered, and that this had been demonstrated at their existing installations. Babcock Power presents the results of filterable PM testing at AES Greenidge in their attached paper, which confirms that extremely low emission levels have been achieved there.

4.5 Mercury Control Capability

The CFB Dry FGD technology offers the benefit of extended residence time of solids in the fluidized bed absorber. At AES Greenidge, which is also equipped with an SCR system for NO_x control, this resulted in consistent mercury control performance above 95 percent removal on a coal-to-stack basis, even without the use of activated carbon, as illustrated in Figure 9 from the attached paper.

5.0 ADDITIONAL ADVANTAGES OF CFB DRY FGD TECHNOLOGY

Comparison of the information presented in Sections 3 and 4 of this report supports the determination that, from an emissions control standpoint, the CFB Dry FGD technology is equivalent to or better than the combination of wet FGD and wet ESP that is the current BART control technology retrofit requirement of the KY RH SIP for Cooper Station Units 1 and 2. In addition, the CFB Dry FGD technology offers several specific advantages for application at Cooper Station. These are noted below.

5.1 Stack Plume Visibility

The use of wet FGD at Cooper will produce the emission from the stack of a persistent water vapor plume which will be visible for miles. In contrast, the CFB Dry FGD technology will normally have no visible stack plume. Only during the coldest winter days will there be a visible stack plume of condensed water vapor evident from the operation of the CFB Dry FGD. This will greatly decrease the aesthetic impact of the FGD installation on the plant's neighbors.

5.2 Aesthetic Impact of Stack

The retrofit of wet FGD technology to a coal-fired power plant typically requires the construction of a new "wet stack". This new stack likely would be constructed to a height equivalent to the "Good Engineering Practice" (GEP) stack height, which is considerably taller than the existing stack at Cooper. The higher stack would increase the aesthetic impact on the surrounding communities. In contrast, the selection of CFB Dry FGD technology will likely allow the existing stack to be reused without any increase in height, thus minimizing the aesthetic impact of the FGD retrofit.

5.3 Water Requirements

The volume of water consumed by a CFB Dry FGD will be substantially less that what would be required for the wet FGD.

5.4 Wastewater Discharge Considerations

The CFB Dry FGD will have no wastewater discharge, whereas the wet FGD technology would produce a wastewater blowdown stream that would require chemical treatment in order to comply with effluent limitations.

5.5 Solid Waste Disposal Considerations

The CFB Dry FGD will produce a dry, powdery waste product that will exhibit handling characteristics very similar to the dry fly ash that is currently being disposed of in the on-site landfill at Cooper Station. In contrast, the wet FGD system will produce a wet sludge that must be dewatered prior to placement in the landfill. The higher moisture content of the wet FGD waste in the landfill may require modifications to the permitting and operation of the landfill.

6.0 CONCLUSIONS

In its development of the "Guidelines for BART Determinations Under the Regional Haze Rule" (40 CFR 51, Appendix Y), EPA intentionally established presumptive BART limits that would retain the flexibility of plant owners to choose either wet FGD or dry FGD.

> *...we are establishing a presumptive BART limits of 95 percent SO_2 removal, or an emission rate of 0.15 lb SO_2/mmBtu...*
> *...We requested comment on the removal effectiveness of flue gas desulfurization (''FGD'' or ''scrubber'' controls) for various coal types and sulfur content combinations. Having considered the comments received, we have determined that there is ample data to support the determination that the BART presumptive limits outlined in today's action are readily achievable by new wet or semi-dry FGD systems across a wide range of coal types and sulfur*

contents based on proven scrubber technologies currently operational in the electric industry. [70 FR 39132]

As the information presented in Section 2 of this report has demonstrated, the currently stated BART retrofit technology for PM control (wet FGD and wet ESP) in the KY RH SIP for Cooper Units 1 and 2 is unduly restrictive, in conflict with EPA's stated intent that either wet FGD or dry FGD technologies may be selected as BART. This is due, at least in part, to misrepresentations of the Consent Decree and poor assumptions that were made in the preparation of the "BART Analysis for PM Emissions", which was subsequently submitted to KYDAQ on behalf of EKPC.

The BART Analysis should have considered available alternatives to the "wet FGD / wet ESP" combination. These alternatives, which include CFB Dry FGD technology, were known to EPA as early as November 2000 and were specifically recommended by EPA in its July 2005 "BART Guideline" for consideration in the identification of BART alternatives.

The information presented in Sections 3 and 4 of this report has demonstrated that, from an emissions control perspective, the CFB Dry FGD technology is clearly equivalent to, or better than, the "wet FGD / wet ESP" technology combination. Specifically, the demonstrated and anticipated guaranteed emissions control performance of the CFB Dry FGD technology for SO_2, H_2SO_4 (condensable PM) and filterable PM is equal to or better than what could be expected from the wet FGD / wet ESP combination. Limited information indicates that mercury control for the CFB Dry FGD may also be greater than that for the wet FGD / wet ESP combination. In comparison to the wet ESP technology specifically, the CFB Dry FGD technology actually has a greater degree of demonstrated performance on coal-fired utility boilers.

In addition, as detailed in Section 5, the CFB Dry FGD technology has advantages over the "wet FGD / wet ESP" combination in the areas of stack plume visibility, aesthetic impacts, water usage, wastewater discharge and solid waste disposal. In a situation where two alternative technologies are essentially equivalent, consideration of these additional factors would likely swing the BART determination clearly in the direction of establishing the CFB Dry FGD technology as BART.

* * * * *

Attachments:

- Technical Paper " The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation", presented at the Power Plant Air Pollutant Control "Mega" Symposium, August 28, 2008.
- Letter from Allied Environmental Solutions dated 15 September 2008
- Letter from Babcock Power Environmental dated September 12, 2008

The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation

Paper # 15

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ABSTRACT

The Greenidge Multi-Pollutant Control Project is being conducted at the 107-MW AES Greenidge Unit 4 as part of the U.S. Department of Energy's (DOE) Power Plant Improvement Initiative (PPII) to demonstrate an innovative combination of technologies that is well-suited for reducing emissions from the nation's large fleet (~60 GW) of smaller coal-fired units. The technologies, which include a NOxOUT CASCADE® hybrid selective non-catalytic reduction / selective catalytic reduction (SNCR/SCR) system and a Turbosorp® circulating fluidized bed dry scrubber, were installed in 2006 with a capital cost of < \$350/kW and a footprint of < 0.5 acre, substantially less than the cost and space that would have been required for a conventional SCR and wet scrubber.

Testing in 2007 with 2.4-3.2% sulfur coal demonstrated the system's ability to reduce NO_x emissions to 0.10 lb/mmBtu and emissions of SO_2, SO_3, and HCl by 96-97%. Mercury emissions were reduced by more than 95% without any activated carbon injection (ACI). Additional tests have been conducted through mid-2008 to establish the effects of plant operating conditions on the performance of the multi-pollutant control system. These tests have consistently shown at least 95% SO_2 removal, $\geq$ 95% mercury removal (with no activated carbon injection), and very low emissions of SO_3, HCl, and particulate matter. NO_x emissions have averaged between 0.10 and 0.15 lb/mmBtu during longer-term operation. The performance of the multi-pollutant control system during its first year of commercial operation is discussed, and process economics are presented.

INTRODUCTION

The Greenidge Multi-Pollutant Control Project is being conducted as part of the U.S. Department of Energy's Power Plant Improvement Initiative to demonstrate an air emissions control retrofit option that is well-suited for the nation's vast existing fleet of smaller, uncontrolled coal-fired electric generating units (EGUs). There are about 420 coal-fired EGUs in the United States with capacities of 50-300 MW_e that currently are not equipped with selective catalytic reduction, flue gas desulfurization (FGD), or mercury control systems. These smaller units are a valuable part of the nation's energy infrastructure, constituting almost 60 GW of installed capacity. However, with the onset of various state and federal environmental regulations requiring deep reductions in emissions of SO_2, NO_x, and Hg, the continued operation of these units increasingly depends upon the ability to identify viable air pollution control retrofit options for them. The large capital costs and sizable space requirements associated with conventional technologies such as SCR and wet FGD make these technologies unattractive for many smaller units.

The Greenidge Project seeks to establish the commercial readiness of a multi-pollutant control system that is designed to meet the needs of smaller coal-fired EGUs by offering deep emission reductions, low capital costs, small space requirements, applicability to high-sulfur coals, low maintenance requirements, and good turndown capabilities. The system includes combustion modifications and a NOxOUT CASCADE® hybrid SNCR/SCR system for NO_x control, as well as a Turbosorp® circulating fluidized bed dry scrubber for SO_2, SO_3, HCl, and HF control. A baghouse, integral to the Turbosorp® system, provides particulate control. Baghouse ash is recycled to the scrubber to improve sorbent utilization. Mercury control is accomplished via the co-benefits afforded by the in-duct SCR, Turbosorp® scrubber, and baghouse, and, if required, by injection of activated carbon upstream of the scrubber.

The multi-pollutant control system is being demonstrated at the 107 MW_e (Energy Information Administration net winter capacity) AES Greenidge Unit 4 in Dresden, NY. Unit 4 (Boiler 6) is a 1953-vintage, tangentially-fired, balanced draft, reheat unit that fires pulverized eastern U.S. bituminous coal as its primary fuel and can co-fire biomass (waste wood) at up to 10% of its heat input. As such, it is representative of many of the 420 smaller coal-fired units described above. Before the multi-pollutant control project, the unit was equipped with a separated overfire air (SOFA) system for NO_x control and an electrostatic precipitator (ESP) for particulate matter control; fuel sulfur content was restricted in order to meet its permitted SO_2 emission rate of 3.8 lb/mmBtu.

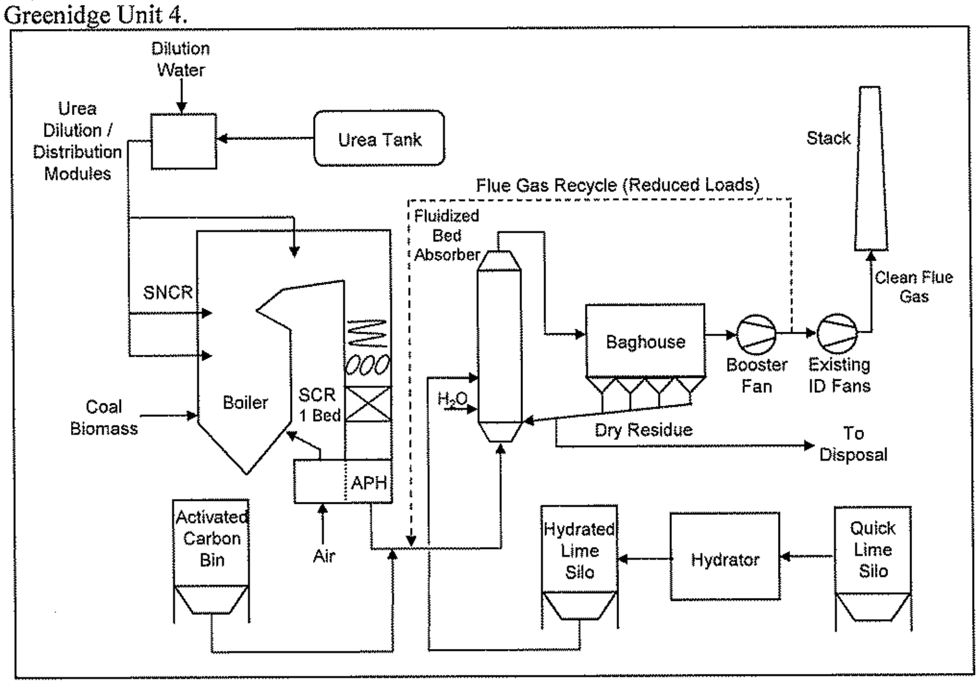
The Greenidge Project is being conducted by a team including CONSOL Energy Inc. Research & Development (CONSOL R&D) as prime contractor (responsible for project administration, performance testing, and reporting), AES Greenidge LLC as host site owner (responsible for site management, permitting, and operation of the multi-pollutant control system), and Babcock Power Environmental Inc. (BPEI) as engineering, procurement, and construction (EPC) contractor. The NOxOUT CASCADE® technology was supplied by Fuel Tech under subcontract to BPEI; the SCR reactor was supplied by BPEI, and the Turbosorp® technology was supplied by BPEI under license from Austrian Energy and Environment. All funding for the project is being provided by the U.S. DOE, through its National Energy Technology Laboratory, and by AES Greenidge. The overall goal of the Greenidge Project is to show that the multi-pollutant control system being demonstrated, which had a capital cost of less than \$350/kW and occupies less than 0.5 acre for the AES Greenidge Unit 4 application, can achieve full-load NO_x emissions of $\leq$ 0.10 lb/mmBtu, reduce SO_2 and acid gas (SO_3, HCl, and HF) emissions by $\geq$ 95%, and reduce Hg emissions by $\geq$ 90%, while the unit is firing 2-4% sulfur eastern U.S. bituminous coal and co-firing up to 10% biomass.

Start-up and commissioning of the multi-pollutant control system at AES Greenidge were completed in early 2007, and the system has now operated commercially for more than one year. During that time, the performance of the multi-pollutant control system has been monitored closely using plant operating data and data that were generated during a series of performance testing campaigns led by CONSOL R&D. This paper focuses on key performance results observed between March 2007 and May 2008. Process economics incorporating these performance results are also presented.

PROCESS DESIGN

Figure 1 presents a schematic of the multi-pollutant control process that is being demonstrated as part of the Greenidge Project. The design for AES Greenidge Unit 4 retrofit is based on the use of a 2.9%-sulfur bituminous coal, co-fired with up to 10% waste wood, and on a baseline full-load NO_x emission rate of ~ 0.30 lb/mmBtu prior to the installation of the new combustion modifications.

Figure 1. Schematic of the multi-pollutant control process being demonstrated at AES Greenidge Unit 4.



NO_x control is the first step in the process and is accomplished using urea-based, in-furnace SNCR followed by a single-layer SCR reactor that is installed in a modified section of the ductwork between the unit's economizer and its two air heaters. The SCR process is fed exclusively by ammonia slip from the SNCR process. Static mixers located just upstream of the SCR are used to homogenize the velocity, temperature, and composition of the flue gas to promote optimal ammonia utilization and NO_x reduction across the relatively small SCR catalyst, which consists of a single layer that is ~ 1.3 meters deep. Because the SCR reactor is able to consume ammonia slip (typically a limiting factor in SNCR design), the upstream SNCR system can operate at lower temperatures than a stand-alone SNCR system would, resulting in improved urea utilization and greater NO_x removal by the SNCR system, as well as sufficient NH_3 slip to permit additional NO_x

reduction via SCR. The hybrid NO_x control system at AES Greenidge Unit 4 also includes combustion modifications (low-NO_x burners and SOFA) to achieve further reductions in NO_x emissions and to improve the performance of the hybrid SNCR/SCR system. Hence, the system is designed to achieve a full-load NO_x emission rate of ≤ 0.10 lb/mmBtu by combining the combustion modifications, which are designed to produce NO_x emissions of 0.25 lb/mmBtu, the SNCR, which is designed to reduce NO_x by ~ 42% to 0.144 lb/mmBtu, and the SCR, which is designed to further reduce NO_x by $\geq 30\%$ to ≤ 0.10 lb/mmBtu. The SNCR system at AES Greenidge includes three zones of urea injection. At high generator loads, urea is injected into the mid- and low-temperature zones to maximize NO_x removal and generate ammonia slip for the SCR reactor. At generator loads that produce economizer outlet temperatures below the minimum operating temperature for the SCR reactor, urea injection into the lowest-temperature zone is discontinued; however, urea continues to be injected into one or both of the mid- and high-temperature zones until the minimum SNCR operating temperature is reached, resulting in continued NO_x removal of 20-25% via SNCR. Below the minimum SNCR operating temperature, NO_x emissions continue to be controlled by the unit's low-NO_x combustion system.

Emissions of SO_2 and other acid gases are reduced by $\geq 95\%$ in the Turbosorp® circulating fluidized bed dry scrubber system, which is installed downstream of the air heaters. In the Turbosorp® system, water and dry hydrated lime ($Ca(OH)_2$), which is produced from pebble lime in an onsite hydrator installed as part of the project, are injected separately into a fluidized bed absorber. There, the flue gas is evaporatively cooled to within 45 °F of its adiabatic saturation temperature and brought into intimate contact with the hydrated lime reagent in a fast fluidized bed. The basic hydrated lime reacts with the acidic constituents of the flue gas (i.e., SO_2, SO_3, HCl, and HF) to form dry solid products (i.e., hydrates of $CaSO_3$ and $CaSO_4$, $CaCl_2$, CaF_2), which are separated from the flue gas in a new eight-compartment pulse jet baghouse. More than 95% of the collected solids are recycled to the absorber via air slides in order to maximize pollutant removal and lime utilization. As shown in Figure 1, a flue gas recycle system is also included to provide sufficient flue gas flow to maintain a fluidized bed in the absorber at low-load operation. A new booster fan, which was installed upstream of the unit's existing induced-draft fans to overcome the pressure drop created by the installation of the in-duct SCR, fluidized bed absorber, and baghouse, provides the motive force for flue gas recycle. The booster fan accounts for a majority of the multi-pollutant control system's parasitic power requirement, which totals about 1.8% of the net electric output of AES Greenidge Unit 4.

Because water and dry hydrated lime are injected separately into the Turbosorp® absorber vessel, the hydrated lime injection rate is controlled solely by the SO_2 loading in the flue gas and by the desired SO_2 emission reduction, without being limited by the flue gas temperature or moisture content. As a result, the Turbosorp® system affords greater flexibility than a spray dryer for achieving deep emission reductions from a wide range of fuels, including high-sulfur coals. This is an important feature, as more than 80% of the 420 candidate units identified earlier are located east of the Mississippi River, where high-sulfur coal is a potential fuel source. The high solids recycle rate from the baghouse to the absorber vessel promotes efficient sorbent utilization in the Turbosorp® system. The projected calcium-to-sulfur (Ca/S) molar ratio for the design fuel (4.0 lb SO_2 / mmBtu) is 1.6-1.7, based on moles of inlet SO_2. Finally, unlike wet FGD systems and spray dryers, the Turbosorp® system does not require slurry handling. This is expected to result in reduced maintenance requirements relative to the alternative technologies.

Mercury control in the multi-pollutant control system is accomplished via the co-benefits afforded by the combustion modifications, in-duct SCR, circulating fluidized bed dry scrubber, and baghouse, and, if required, by injection of activated carbon just upstream of the scrubber. From a mercury control perspective, the Greenidge multi-pollutant control process is similar to a conventional air pollution control configuration comprising an SCR, spray dryer, and baghouse. Measurements have demonstrated that this configuration, when applied to plants firing bituminous coal, achieves a high level of mercury removal (i.e., 89-99%) without the need for any mercury-specific control technology.[1] This high level of removal likely results from a combination of factors, including the conversion of elemental mercury (Hg^0) to oxidized mercury (Hg^{2+}) across the SCR catalyst, the removal of Hg^{2+} (a Lewis acid) and SO_3 (which can interfere with Hg adsorption on carbon particles) by moistened, basic $Ca(OH)_2$ particles in the scrubber, and the removal of Hg^{2+} and Hg^0 via adsorption onto carbon-containing fly ash and $Ca(OH)_2$ at low temperatures in the baghouse, which facilitates contact between gaseous mercury and carbon or other sorbent contained in the dust cake that accumulates on its numerous filter bags. The Greenidge multi-pollutant control process includes all of these components, and hence, it might be expected that its combination of an in-duct SCR, $Ca(OH)_2$-based scrubber, and baghouse would result in high mercury removals without any activated carbon injection when applied to bituminous coal-fired units. The combustion modifications (including those that were in place prior to installation of the multi-pollutant control system) also contribute to Hg removal by increasing the unburned carbon content of the fly ash, thereby improving its capacity for Hg capture. In addition, the multi-pollutant control system includes an activated carbon injection system installed upstream of the Turbosorp® absorber vessel. Relative to simple duct injection, very effective utilization of the activated carbon and high mercury capture are expected to result from the high solids recycle ratio, long solids residence time, and low temperature (~160 °F) provided by the circulating fluidized bed dry scrubber and baghouse.

Figures 2 and 3 present photographs of the in-duct SCR reactor and Turbosorp® system, respectively, at AES Greenidge Unit 4. The SCR reactor fits within the existing boiler building in a space with horizontal dimensions of 52 ft by 27 ft and a vertical height of 23 ft. (The cross section of the reactor is 45 ft by 14 ft). Because of this compact reactor design, the hybrid SNCR/SCR system avoids many of the capital costs associated with the multi-layer reactor, structural support steel, foundations, and new ductwork runs required for a conventional stand-alone SCR system. The arrangement of the circulating fluidized bed dry scrubber, baghouse, and associated equipment is also compact. As shown in Figure 3, the various pieces of equipment are vertically tiered to permit gravity-assisted transport of solids where possible, and as a result, the entire installation at AES Greenidge requires only ~ 0.4 acre of land. Unlike a wet FGD system, the Turbosorp® system does not produce a saturated flue gas, and therefore it is constructed from carbon steel and does not entail the installation of a new corrosion-resistant stack. These factors, coupled with the mechanical simplicity of the Turbosorp® system relative to a wet FGD system, contribute to its comparatively lower capital costs.

PERFORMANCE AND COST RESULTS

Circulating Fluidized Bed Dry Scrubber

Guarantee testing of the multi-pollutant control system at AES Greenidge Unit 4 was completed during March – May 2007. The Turbosorp® system demonstrated attainment of its performance target for SO_2 removal efficiency on March 29, achieving 96% removal while the unit fired coal with a sulfur content of 3.8 lb SO_2 / mmBtu. (SO_2 was measured at the scrubber inlet using EPA Method 6C and at the stack using the unit's continuous emissions monitor).

Figure 2. Photograph of the in-duct SCR reactor at AES Greenidge Unit 4.

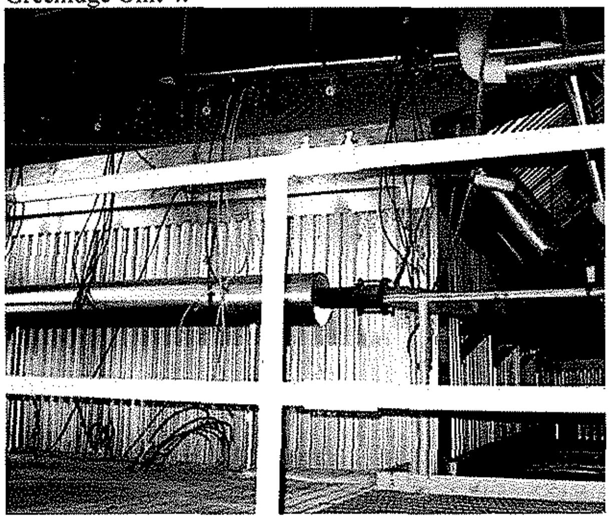
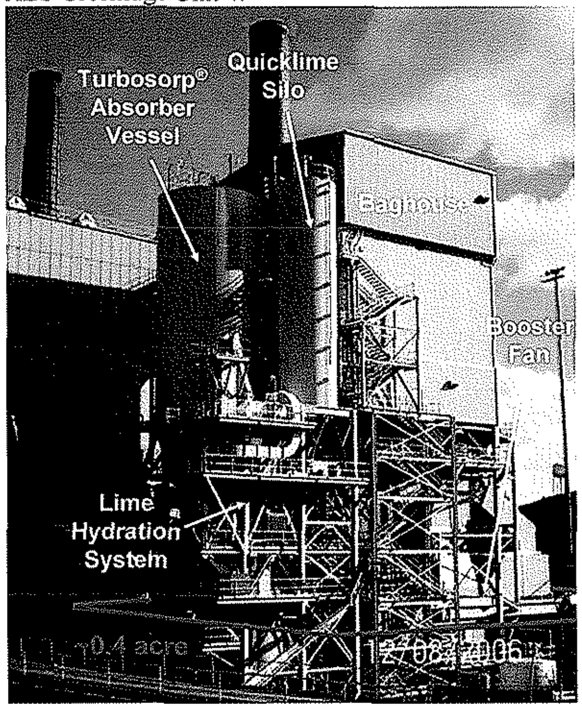


Figure 3. Photograph of the Turbosorp® system at AES Greenidge Unit 4.

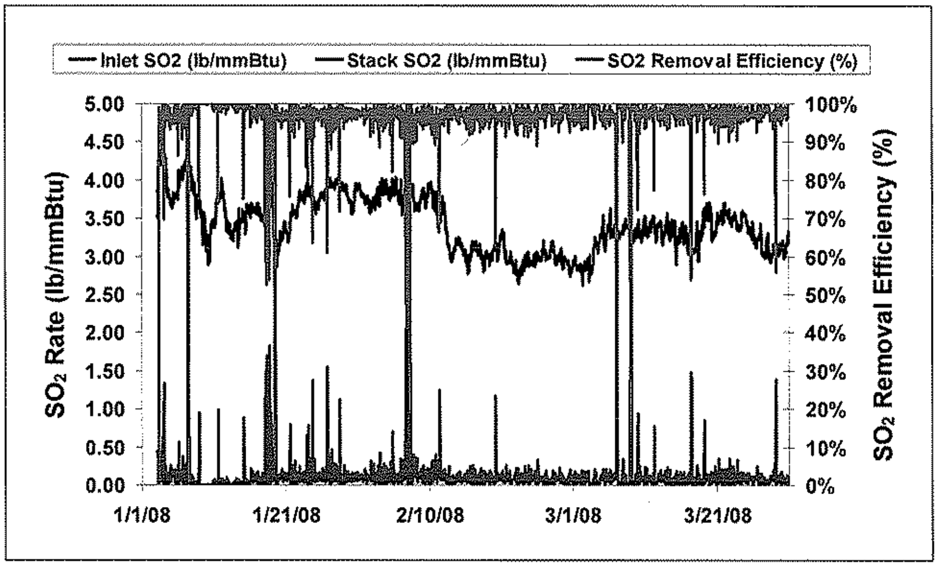


This level of performance continued throughout the first year of operation of the Turbosorp® system while Unit 4 fired mid-to-high sulfur eastern U.S. bituminous coals. To exemplify the longer-term SO_2 reduction efficiency of the circulating fluidized bed dry scrubber, Figure 4 shows the hourly SO_2 rate measured at the Turbosorp® inlet and stack during the first three months of 2008, as well as the hourly SO_2 removal percentages calculated from these data. Hourly average inlet SO_2 rates ranged from 2.62 to 4.52 lb/mmBtu during the quarter. Overall, the Turbosorp® system reduced SO_2 emissions from 3.41 lb/mmBtu to 0.13 lb/mmBtu during January-March, resulting in a removal efficiency of 96.3%.

AES Greenidge routinely operates the scrubber with an SO_2 emission rate set point of 0.10 lb/mmBtu, which is below its permitted emission rate of 0.19 lb/mmBtu (30-day rolling average), in order to provide a margin for transient upsets in system performance. These upsets, which are evidenced by the spikes in stack SO_2 emission rate in Figure 4, can be caused either by routine operating and maintenance activities (e.g., change-out of the water injection lance) or by unexpected equipment problems (e.g., frozen valves and pressure transmitters during cold weather periods). However, such upsets occur infrequently, and the Turbosorp® system has easily maintained SO_2 emissions within the unit's permit limit. The system is also capable of attaining very deep SO_2 removal efficiencies, even when the unit fires high-sulfur coals. During the three months depicted in Figure 4, removal efficiencies ≥ 99% were observed during 23% of the one-hour periods for which SO_2 data were available. Moreover, during performance testing in October

2007, the scrubber achieved 96-97% SO_2 removal while Unit 4 fired coal containing 4.5-4.9 lb SO_2 / mmBtu.

Figure 4. SO_2 removal performance of the Turbosorp® system at AES Greenidge Unit 4 during January-March 2008. Data were obtained from the unit's air heater outlet SO_2 monitor and stack continuous emissions monitor.



The variable operating costs of the Turbosorp® process depend strongly on the amount of hydrated lime required to achieve a given level of SO_2 removal. Ca/S molar ratios (based on inlet SO_2) were estimated during six days of process performance testing in October 2007. Scrubber operating conditions were varied over the course of these six days. The ratios were derived from the pebble lime feed rate, change in hydrated lime silo level, and coal feed rate and sulfur content measured on each day. For each daily ratio, the number of moles of calcium is based on the available $Ca(OH)_2$ content of hydrated lime samples collected on that day, and the number of moles of inlet sulfur is computed as 95% of the sulfur fed with the coal. (Available $Ca(OH)_2$, determined in accordance with ASTM C25, averaged 96% of the total elemental calcium in the samples). It is important to recognize that these Ca/S ratios depend on a number of measurements and, hence, are susceptible to several sources of error. Nevertheless, the ratios generally varied according to expectation. Process conditions on October 9 and 10 (coal sulfur content = 4.1 lb SO_2 / mmBtu, SO_2 removal efficiency = 95%, Turbosorp® outlet temperature = 160 °F) were very similar to the design specification for AES Greenidge Unit 4; the average Ca/S molar ratio computed from process data on these days was 1.68, consistent with the projected range of 1.6-1.7 cited earlier in this paper. Higher Ca/S molar ratios (average = 2.0) were required on the first two days of testing, when the coal sulfur content (average = 4.6 lb SO_2 / mmBtu) and SO_2 removal efficiency (average = 97%) were greater than design conditions, and on the last day, when the scrubber outlet temperature was raised by 5 °F from its typical set point of 160 °F. (The coal sulfur content on this last day of testing was 4.2 lb SO_2 / mmBtu, and the SO_2 removal efficiency was 93%). Additional parametric testing of the Turbosorp® system was conducted on June 16-19, 2008, to elucidate the relationships between SO_2 removal efficiency, approach to adiabatic saturation, and Ca/S; however, results of this testing are not yet available.

Sorbent utilization in the Turbosorp® system was also analyzed over the six-month period from August 1, 2007, through January 31, 2008, using lime delivery data (i.e., truck weights) and SO_2 data from the plant's online analyzers. During this period, the average SO_2 rate measured at the inlet to the Turbosorp® scrubber was 3.83 lb/mmBtu, and the average SO_2 removal efficiency was 95.9%. Lime consumption (measured as available CaO) totaled 10,792 tons, and the amount of SO_2 fed to the scrubber totaled 6,848 tons, resulting in an average Ca/S molar ratio of 1.80. This is slightly greater than the targeted ratio of 1.6-1.7, although the SO_2 removal efficiency was slightly higher than the design efficiency of 95%, and the calculation is susceptible to a number of sources of measurement error, including errors in the truck weights, stack flow rate measurements, available CaO measurements, and SO_2 measurements. (The SO_2 content measured at the scrubber inlet tends to be biased low relative to the coal sulfur content).

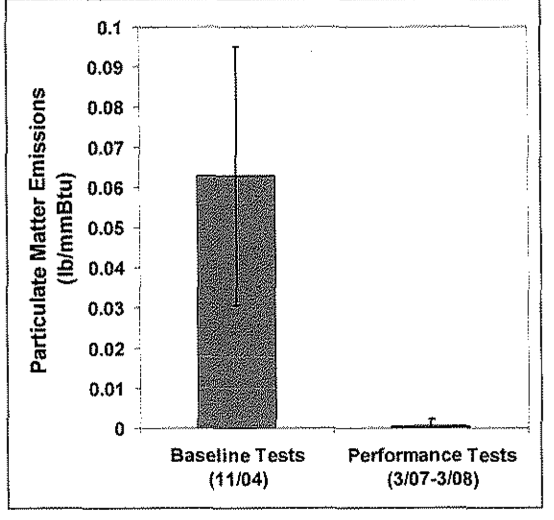
The Turbosorp® system also achieved its performance targets for SO_3 and HCl removal efficiency (both ≥ 95%) during guarantee testing in May 2007. The average SO_3 removal efficiency measured during the May test period (using the controlled condensation method) was 97.1%, and the average HCl removal efficiency measured during that period (using U.S. EPA Method 26A) was 97.2%. (HF concentrations were also measured using Method 26A; however, concentrations at the inlet and outlet of the scrubber were near or below the method detection limit, precluding the determination of a removal efficiency). Table 1 summarizes all of the SO_3 and HCl measurements that have been performed at AES Greenidge Unit 4 through May 2008. The average HCl removal efficiency observed during 18 tests between March 2007 and May 2008 was 96.1%. SO_3 removal efficiencies measured since the guarantee test period have varied considerably, owing largely to variations in SO_3 concentrations at the Turbosorp® inlet. These variations in removal efficiency are likely due to fluctuations in fuel sulfur content, boiler operating conditions, scrubber operating conditions, and SO_3 removal across the air heater. (During the SO_3 tests, unit loads varied from 55 MW_g to 109 MW_g; coal sulfur content varied from 3 lb/mmBtu to 5 lb/mmBtu, and SO_2 removal efficiency varied from < 85% to > 99%). The average SO_3 concentration measured at the stack since the installation of the multi-pollutant control system is 0.7 ppmvd @ 3% O_2; twenty-three of the 26 stack SO_3 concentrations measured to-date were less than 1 ppmvd, which approaches the practical field detection limit of the controlled condensation method. Hence, installation of the Turbosorp® system has resulted in very low SO_3 emissions from AES Greenidge Unit 4.

Table 1. *Summary of results from SO_3 and HCl testing performed at AES Greenidge Unit 4 between March 29, 2007, and May 22, 2008. SO_3 was measured using the controlled condensation method, and HCl was measured using U.S. EPA Method 26A.*

Analyte	Number of Tests	Concentration at Turbosorp® Inlet, ppmvd @ 3% O_2 Mean (Range)	Concentration at Stack, ppmvd @ 3% O_2 Mean (Range)	Removal Efficiency, % Mean (Range)
SO_3	26	12.1 (4.7 - 28.7)	0.7 (0.2 - 1.7)	93.0 (78.8 - 98.4)
HCl	18	36.9 (26.1 - 48.6)	1.4 (0.2 - 2.9)	96.1 (89.5 - 99.4)

Installation of the Turbosorp® system, including a new baghouse, at AES Greenidge Unit 4 has resulted in a substantial reduction in primary (non-condensable) particulate matter (PM) emissions from the unit. Figure 5 compares PM emission rates measured before and after installation of the system (using U.S. EPA Method 5 or 17). The average PM emission rate measured during 30 full-load tests between March 2007 and March 2008, following the installation of the multi-pollutant control system, was < 0.001 lb/mmBtu. This represents a more-than 98% reduction over the baseline full-load PM emission rate of 0.063 lb/mmBtu measured in November 2004. (The average PM emission rate observed during 11 reduced-load tests in November 2007 and May 2008 was similarly < 0.001 lb/mmBtu). The improvement in PM emissions has occurred in spite of the substantial increase in flue gas particulate loading brought about by the hydrated lime, reaction products, and high solids recycle rate in the Turbosorp® system. It results largely from the superior performance of the baghouse relative to the unit's old ESP. Particle agglomeration in the fluidized bed absorber may also contribute to improved PM capture efficiency.

Figure 5. Summary of particulate matter emission rates measured at AES Greenidge Unit 4 before and after installation of the multi-pollutant control system. Error bars represent ± 1 standard deviation.



As discussed above, the Turbosorp® system is mechanically simple relative to many alternative FGD technologies, and therefore, it is expected to afford low maintenance requirements. This has generally been true at AES Greenidge during the first year of operation of the system. AES has been able to operate and maintain the Turbosorp® system (and the rest of the multi-pollutant control system) without adding any new operating and maintenance (O&M) personnel. The majority of the O&M requirements associated with the Turbosorp® system have involved the lime hydration system, which is the most mechanically complex part of the process. The most common problem has been plugging in the hydrated lime classification system. Problems with the lime hydration system have usually been resolved without impacting the operation of the Turbosorp® scrubber. Plant personnel can continue to operate the scrubber while the hydrator is offline by using hydrated lime from their onsite inventory or by taking deliveries of hydrated lime. However, in a few instances, lack of hydrated lime availability has forced the unit to derate. Hence, AES is increasing the plant's onsite storage capacity for hydrated lime. Other routine maintenance requirements in the Turbosorp® system include changing out and cleaning the Turbosorp® water injection lance (about once per week) and unplugging the vents from the ash disposal silos (several times per day). In addition, there have been occasional problems with malfunctioning instruments and with plugging of lines and valves in the ash recirculation and disposal system. However, no condensation problems have been observed in the absorber vessel or baghouse.

The only major byproduct from the multi-pollutant control system is the product ash from the Turbosorp® system, which is very similar to spray dryer ash. Approximately 3.2 tons of scrubber byproduct (excluding fly ash) are produced for each ton of SO_2 removed, assuming design conditions. AES Greenidge generally disposes of the product ash at a landfill adjacent to the plant site. However, plant personnel succeeded in supplying 3,500 tons of product ash for use as flowable fill, and the project team continues to seek potential beneficial reuses for the ash, which could also include use in mine reclamation or use in manufactured aggregate production.

Hybrid NO_x Control System

The hybrid NO_x control system has significantly reduced NO_x emissions from AES Greenidge Unit 4, although it has performed less optimally than the Turbosorp® system. During guarantee testing on March 28, 2007, the combustion modifications and hybrid SNCR/SCR system demonstrated an average full-load NO_x emission rate of 0.10 lb/mmBtu, thereby satisfying the project's performance target for NO_x emissions. However, AES Greenidge has been unable to achieve this emission rate in the long term while also maintaining acceptable combustion characteristics, sufficiently high steam temperatures, and sufficiently low ammonia slip for routine operation. During the guarantee test period, the unit experienced flame attachments that damaged several burners, forcing plant personnel to reduce the aggressiveness of low-NO_x firing. This change in turn caused boiler conditions to deviate from the design basis for the SNCR system, promoting less-than-optimal performance of that system. The NO_x control problems have been exacerbated by the accumulation of large particle ash (LPA) in the in-duct SCR reactor, which contributes to decreased NO_x removal efficiency and increased ammonia slip from the reactor. As a result, the unit has generally operated with high-load NO_x emissions of 0.10-0.15 lb/mmBtu since the guarantee testing period.

Figure 6 shows average NO_x emissions from AES Greenidge Unit 4 as a function of gross generator load during the first three months of 2008. As illustrated in the figure, the unit's permit limit varies according to the turndown strategy for the hybrid NO_x control system. The permitted NO_x emission rate is 0.15 lb/mmBtu for gross generator loads above 68 MW, but it increases to 0.28 lb/mmBtu when the gross generator load is between 53 and 68 MW and to 0.35 lb/mmBtu when the gross generator load is between 43 and 52 MW. The overall average NO_x emission rate during January-March 2008 was 0.15 lb/mmBtu. The average NO_x emission rate for gross generator loads above 68 MW was 0.14 lb/mmBtu, and the average rate for gross generator loads between 53 and 68 MW was 0.23 lb/mmBtu. This NO_x emission profile is typical of that observed at AES Greenidge Unit 4 during the first year of operation of the multi-pollutant control system.

Figure 7 illustrates the relationship between unit load, urea injection scheme, and ammonia slip for the hybrid SNCR/SCR system at AES Greenidge Unit 4. Data were obtained during parametric testing of the system in November 2007 and May 2008. As discussed earlier, at low load, urea is only injected into Zone 1 (high-temperature zone), and at high load, urea is only injected into Zone 2 (mid-temperature zone) and Zone 3 (low-temperature zone). Injection of urea into lower-temperature regions of the boiler generates ammonia; however, the SCR reactor is designed to consume almost all of this ammonia via reaction with NO_x, leaving very little ammonia slip at the air heater inlet. Ammonia slip can cause ammonium bisulfate fouling in the air heaters; hence, it is a particular concern for plants like AES Greenidge that fire high-sulfur coal. The project's targeted ammonia slip for all unit loads is ≤ 2 ppmvd (corrected to 3% O_2) at the air heater inlet.

As shown in Figure 7, the ammonia slip is well within this target at low unit load, but it increases rapidly upon introduction of urea into Zone 2 at intermediate load. Ammonia slip concentrations measured at mid and high unit loads during the project's performance evaluation period have ranged from 2 to 7 ppmvd @ 3% O_2. Thus far, the higher-than-expected ammonia slip has not significantly affected unit operability or byproduct handling, as it has only led to a need for periodic washing of the air heater baskets. However, the effect of ammonia slip will continue to be monitored as catalyst activity decreases with time.

Figure 6. NO_x emissions (stack continuous emissions monitor) as a function of gross load at AES Greenidge Unit 4 during January-March 2008. The red line indicates the unit's permit limit (30-day rolling average).

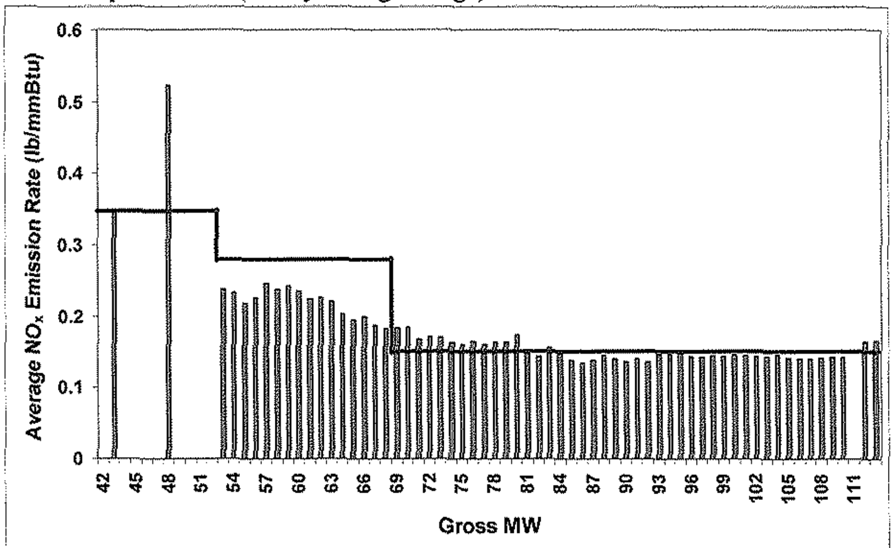
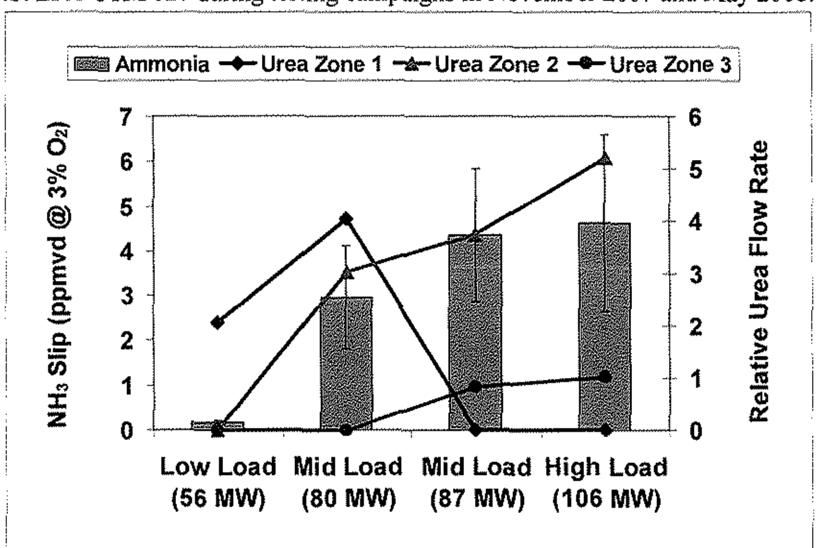


Figure 7. Ammonia slip as a function of gross unit load and urea injection regime at AES Greenidge Unit 4. Ammonia was measured at the air heater inlet using U.S. EPA CTM 027 during testing campaigns in November 2007 and May 2008.

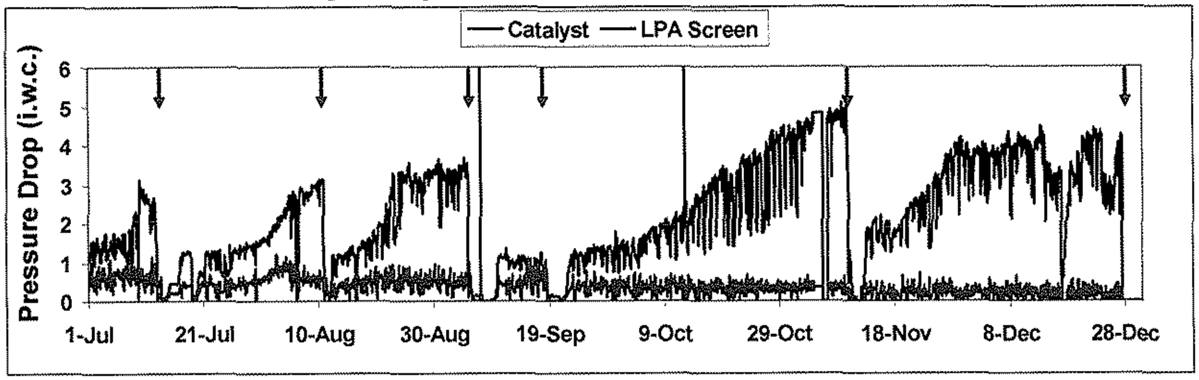


Ammonium bisulfate fouling is also promoted by high concentrations of SO_3 in the flue gas. The catalyst in the hybrid SNCR/SCR system fosters the oxidation of a small portion of SO_2 to SO_3. During performance testing of the multi-pollutant control system in March 2008, SO_3 concentrations were measured at the inlet and outlet of the SCR reactor, as well as at the air heater outlet and stack, in order to evaluate the SO_2-to-SO_3 conversion across the catalyst. The average SO_3 concentrations measured during four test runs were 10.1 ppmvd at the SCR inlet, 18.4 ppmvd at the SCR outlet, 7.7 ppmvd at the air heater outlet, and 0.7 ppmvd at the stack (all concentrations corrected to 3% O_2). The increase in SO_3 concentration across the SCR reactor corresponded to an SO_2-to-SO_3 conversion rate of 0.5%, which is within the project's target of < 1% conversion. The significant decrease in the measured SO_3 concentration between the SCR outlet and air heater outlet may reflect the formation of ammonium bisulfate in the air heaters, especially given the relatively high ammonia slip (5.9 ppmvd @ 3% O_2) observed during the test period. It may also result simply from the condensation of SO_3 as sulfuric acid on the air heater baskets and its subsequent loss to the incoming combustion air.

The most troublesome problem encountered during operation of the multi-pollutant control system at AES Greenidge has been the accumulation of large particle ash in the in-duct SCR reactor. The LPA, which consists of pieces of slag that in many cases are too large to pass through the honeycomb catalyst, becomes lodged in the catalyst channels and promotes subsequent accumulation and bridging of fly ash, eventually plugging a substantial portion of the catalyst. This causes an increase in the pressure drop across the SCR reactor. At AES Greenidge, the pressure drop becomes substantial enough over time that it could cause downstream ductwork to collapse. As a result, the unit must be derated and/or taken offline for catalyst cleaning. LPA accumulation in the SCR catalyst can also contribute to decreased NO_x removal efficiency, increased ammonia slip, and increased catalyst erosion.

The development of an effective LPA removal system for the in-duct SCR at AES Greenidge Unit 4 has been very challenging. The flue gas flows vertically downward between the economizer and SCR reactor, with no available 90° bends or hoppers that can be used for inertial capture of the LPA (as is often done in conventional SCR installations). The solution that has been implemented consists of a sloped screen installed in the ductwork between the economizer and the catalyst to remove the LPA from the flue gas. The screen crosses an expansion joint, and hence, it is installed in two sections. Eight vacuum ports were installed at the base of the screen to remove the collected LPA; soot blowers are located beneath the screen to help transport the LPA to the vacuum ports. The screen, vacuum ports, and two soot blowers were originally installed in May 2007. In September 2007, the two soot blowers were replaced with four rotary soot blowers, and a spring seal was installed to close the gap between screen sections. A rake soot blower was also installed above the SCR catalyst to aid in resuspending accumulated fly ash. In spite of these improvements, however, LPA particles that were large enough to plug the catalyst still passed the screen. This is evident in Figure 8, which shows the pressure drop across the SCR catalyst and LPA screen as a function of time from July-December 2007. Accumulated LPA and fly ash were cleaned from the reactor during six outages in this six-month period. (Four of these outages were a direct result of the LPA problem, and two were caused by other plant problems). In late 2007, patches were installed to eliminate openings in several areas of the screen, and the catalyst was replaced with a clean layer. Unit 4 operated from January 3-May 2, 2008, without an outage, although it was derated for the last month of this period because of elevated pressure drop across the in-duct SCR reactor and air heaters. In May 2008, the existing LPA screen was removed and replaced with a new, smaller-pitch screen to more efficiently remove small pieces of LPA from the flue gas. It is expected that this will significantly reduce the severity of the SCR plugging problem.

Figure 8. Pressure drop measured across the SCR catalyst and LPA screen at AES Greenidge Unit 4, July - December 2007. Red arrows indicate outages during which the SCR reactor was cleaned.

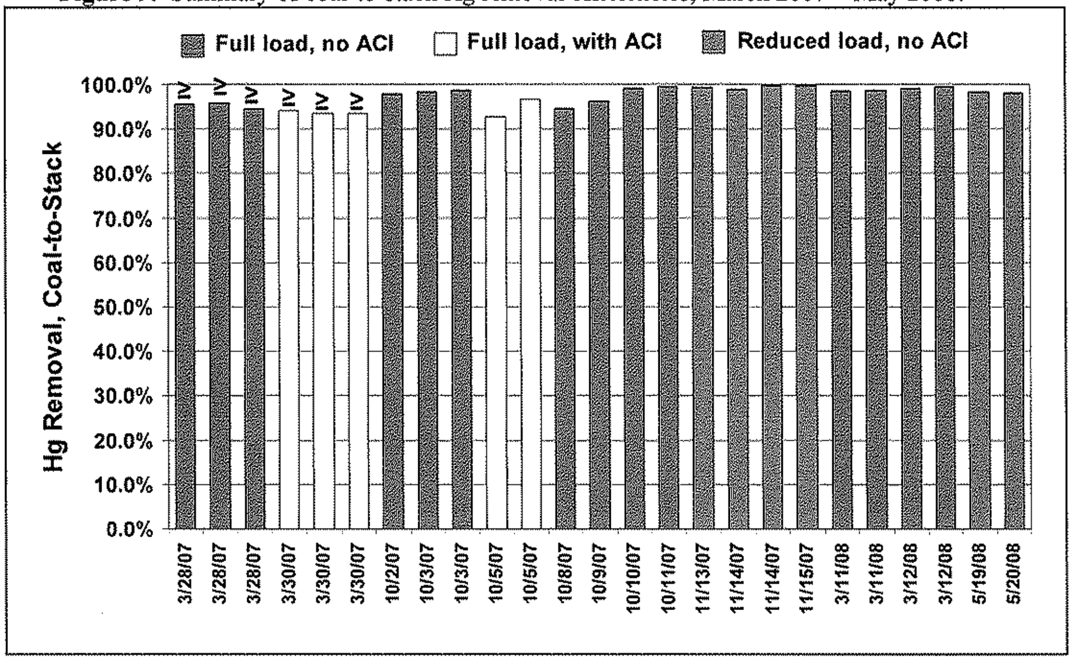


Mercury Control

The multi-pollutant control system at AES Greenidge Unit 4 has consistently exceeded its performance target of ≥ 90% Hg removal efficiency. As shown in Figure 9, twenty-five mercury tests were completed at AES Greenidge between March 2007 and May 2008. For each test, Hg concentrations at the stack were determined using the Ontario Hydro method (ASTM D 6784-02), and Hg concentrations in the coal were determined by ASTM D 6722. (For the first six tests, Hg was determined in the Ontario Hydro samples using cold vapor atomic absorption spectroscopy, and all Hg concentrations at the stack were below the method detection limit. Cold vapor atomic fluorescence spectroscopy was employed for subsequent tests so that stack Hg concentrations could be detected). All of the tests surpassed the project's target for Hg removal; measured coal-to-stack Hg removal efficiencies ranged from 92.8% to 99.8%. Moreover, 20 of the 25 tests were conducted without any activated carbon injection; the average Hg removal efficiency observed during these tests was 98.1%. (The activated carbon injection rate during the five tests that included ACI was approximately 3 lb/mmacf). High mercury removal efficiency was observed irrespective of plant operating conditions. During all of the test periods, AES Greenidge Unit 4 fired typical eastern U.S. bituminous coals containing 6.4 – 13.7 lb Hg / TBtu, 3.3 – 4.9 lb SO_2 / mmBtu, and 0.07 – 0.11 % (dry) Cl. For the four tests on March 11-12, 2008, it also co-fired sawmill waste wood at less than 5% of the total heat input. The gross generator load during the reduced-load tests on November 13-15, 2007, and May 19-20, 2008, ranged from 56 to 84 MW; during the other 19 tests, the unit operated between 105 and 109 MW_{gross}. AES Greenidge Unit 4 produces fly ash with appreciable amounts of unburned carbon. The fly ash carbon content ranged from 9.2 to 25.3% over the course of the 25 Hg tests, likely contributing to the high Hg removal efficiencies that were observed.

As discussed above, the in-duct SCR reactor is also expected to contribute to the high Hg removal efficiency by converting some elemental mercury to oxidized mercury, which is more easily captured in the circulating fluidized bed dry scrubber. Hg oxidation is often observed across conventional SCR reactors, but the extent to which Hg would be oxidized across the comparatively small in-duct SCR at AES Greenidge Unit 4 was uncertain when the process was being designed. To investigate Hg oxidation across the in-duct SCR catalyst, concentrations of Hg^0 and Hg^{2+} were measured at the inlet and outlet of the SCR reactor during the four tests on March 11-12, 2008. These measurements were conducted using a modified version of the Ontario Hydro method, in which sampling was performed at a constant, reduced flow rate, with the nozzle oriented away from the direction of flow to reduce uptake of particulate matter. (Hg speciation results determined using the Ontario Hydro method can be biased in high-dust locations by adsorption of Hg onto the fly ash that is collected on the sample filter. The fly ash can also promote Hg oxidation. However, these artifacts are expected to be minimal at the high temperatures around the SCR. The likelihood of bias is further reduced if the fly ash uptake is minimized. It is also important to note that the Ontario Hydro method has not been validated for high-temperature testing; however, flue gas conditions were similar at the SCR inlet and outlet, reducing the probability of relative measurement bias between those locations, and total Hg concentrations determined at both locations showed reasonable agreement with the coal Hg content and feed rate.) On average, Hg^{2+} accounted for 70% of the total gas-phase Hg (i.e., Hg^0 + Hg^{2+}) at the SCR inlet, and it accounted for 96% of the total gas-phase Hg at the SCR outlet. This result supports the role of the in-duct SCR in oxidizing Hg. Additional Hg measurements were performed around the SCR reactor in May and June 2008 to confirm the data from March; however, results of those additional measurements are not yet available.

Figure 9. Summary of coal-to-stack Hg removal efficiencies, March 2007 – May 2008.



Process Economics

Table 2 summarizes the estimated economic performance of the multi-pollutant control system at AES Greenidge Unit 4. The process economics are expressed in constant 2005 dollars, consistent with the start of construction at AES Greenidge, and are based on design information and actual cost and operating data (where available) for the Unit 4 installation. Key assumptions are listed below the table.

Table 2. Process economics (constant 2005 dollars) for the multi-pollutant control system at AES Greenidge Unit 4.

	EPC Capital Cost ($/kW)	Fixed O&M Costs ($/MWh)	Variable O&M Costs ($/MWh)	Total Levelized Cost
NO_x Control	114[a]	0.39	0.84	$3,487 / ton NO_x
SO_2 Control	229[b]	0.88	5.62	$586 / ton SO_2

[a]Includes combustion modifications, SNCR, in-duct SCR, static mixers, and LPA removal system. [b]Includes scrubber, process water system, lime storage and hydration system, baghouse, ash recirculation system, and booster fan. Assumptions: Plant size = 107 MW net, Capacity factor = 80%, Coal sulfur = 4.0 lb SO_2 / mmBtu, NSR = 1.35, Ca/S = 1.68 mol/mol, Pebble lime available CaO = 90%, NO_x emissions = 0.10 lb/mmBtu, SO_2 removal efficiency = 95%, Parasitic power = 1.84% of net load, 50% urea solution = $1.35/gal, Pebble lime = $115/ton, Waste disposal = $17/ton, Internal COE = $40/MWh, Plant life = 20 years, Fixed charge factor = 13.05%, AFUDC = 2.35%, Other assumptions based on Greenidge design basis, common cost estimating practices, and market prices.

The total EPC capital cost for the multi-pollutant control system (excluding the ACI system, but including all other ancillary equipment) was $343/kW. This is about 40% less than the estimated cost to retrofit AES Greenidge Unit 4 with conventional SCR and wet FGD systems. Costs for the activated carbon injection system are not shown in Table 2, because testing has shown that the ACI system is not needed to achieve the project's Hg removal target. If included, the ACI system would add about $6/kW to the EPC capital cost.

As discussed above, no new employees were required to operate the multi-pollutant control system at AES Greenidge. However, the fixed O&M costs presented in Table 2 preliminarily assume 16 hours per day of operating labor to account for increased overtime and training arising from the system. Maintenance labor and materials costs are estimated as 1.5% of the total plant cost (40% labor, 60% materials), and administrative and support labor costs are estimated as 30% of total O&M labor costs. Actual fixed O&M costs will be tabulated at the end of the project's performance evaluation period.

Variable O&M costs include costs for pebble lime, urea, waste disposal, electricity, water, replacement catalyst, and replacement baghouse bags and cages. These costs were calculated using actual pricing and operating data from AES Greenidge, where available. Urea and pebble lime account for more than half of the variable O&M costs for the NO_x and SO_2 control systems, respectively. Costs for urea were computed assuming a normalized stoichiometric ratio (NSR = 2 x moles of urea ÷ moles of inlet NO_x) of 1.35, consistent with that observed during guarantee testing of the multi-pollutant control system in March 2008. (The process economics in Table 2 assume a NO_x emission rate of 0.10 lb/mmBtu, even though NO_x emissions have averaged higher than this during routine operation of the multi-pollutant control system). Costs for lime assume a Ca/S molar ratio of 1.68, per the October 2007 performance testing results that were presented earlier.

Total levelized costs for the multi-pollutant control system, including levelized capital and fixed and variable O&M costs, are about $3,487 / ton of NO_x removed and $586 / ton of SO_2 removed. These prices also cover mercury control, acid gas control, and improved primary particulate matter control, which are co-benefits of the SO_2 and NO_x control systems and add no incremental cost. Installation of the multi-pollutant control system has enabled AES Greenidge Unit 4 to satisfy its air emissions requirements while remaining profitable, thereby contributing to a 20-30 year life extension for the unit.

SUMMARY

In conclusion, the Greenidge Project has demonstrated the commercial viability of a multi-pollutant control system that is designed to meet the needs of small coal-fired power plants that have traditionally been difficult to retrofit. The system, which includes combustion modifications, a hybrid SNCR/SCR system, and a circulating fluidized bed dry scrubber (with new baghouse), required an EPC capital cost of $343/kW ($2005) and a footprint of < 0.5 acre at the 107-MW AES Greenidge Unit 4. This is substantially less than the capital cost and space that would have been required to retrofit the unit with conventional SCR and wet FGD systems. The multi-pollutant control system has operated commercially for more than a year, and it has generally met or exceeded the project's performance targets. Tests completed since start-up of the system in early 2007 have consistently shown ≥ 95% SO_2 removal, ≥ 95% mercury removal (with no activated carbon injection), and very low emissions of SO_3, HCl, HF, and particulate matter. SO_2 removal efficiencies greater than 95% have been observed even when the unit fires high-sulfur coals containing up to 4.9 lb SO_2 / mmBtu. The performance of the hybrid SNCR/SCR system has been affected by problems with large particle ash, ammonia slip, and less-than-optimal combustion characteristics, and NO_x emissions have typically averaged closer to 0.15 lb/mmBtu than to the targeted emission rate of 0.10 lb/mmBtu. Nevertheless, the system has substantially improved the unit's NO_x emission profile. Further testing of the multi-pollutant control system at AES Greenidge Unit 4 was completed in June 2008; results from those tests will add to the data presented here. Information generated as part of the Greenidge Project is useful for informing the decisionmaking of generators seeking affordable retrofit options for their smaller coal-fired units.

ACKNOWLEDGMENT AND DISCLAIMER

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LLIED
ENVIRONMENTAL SOLUTIONS, INC.

15 September 2008

Burns and McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Attention: Carl Weilert

Subject: CFB Scrubber Emissions Performance

Mr. Weilert,

It was a pleasure talking with you regarding Allied Environmental Solutions air pollution control technologies. Allied offers a full range of technologies for the power generation market as outlined below:

<u>SO_2 Control</u>
- Open spray tower limestone wet FGD scrubber
- Circulating Fluid Bed (CFB) dry FGD scrubber

<u>Dry Particulate Control</u>
- Pulse jet fabric filters (PJFF)
- Rigid electrode electrostatic precipitators (ESP)

<u>Acid Mist Control</u>
- Vertical flow wet electrostatic precipitators

<u>NO_x Control</u>
- Selective Catalytic Reduction (SCR)

With regard to our FGD technologies you asked how a wet FGD scrubber followed by a wet ESP would compare on emissions performance with the CFB dry scrubber followed by a pulse jet fabric filter. Specifically, you were interested in a case were a 4 to 6 #/MM Btu bituminous coal was being burned. While there are certainly differences in terms of capital and operating expense we view these two technology offerings as equivalent in terms of emissions performance and would guarantee the following emissions performance for the CFB / PJFF system:

- SO_2 – 99% removal down to 0.022 #/MM Btu
- H_2SO_4 – 99% removal down to 1 ppm dry at 3% O_2 which is

Allied Environmental Solutions, Inc.
9730 Patuxent Woods Drive, Suite 100 • Columbia, MD 21046
Tel.: 410.910.5100 • Fax 410.910.5101 • E-Mail: info@allied-env.com

ALLIED ENVIRONMENTAL SOLUTIONS, INC.

equivalent to approximately 0.003 to 0.0035 #/MM Btu

- Filterable Particulate Matter – 0.012#/MM Btu
- Mercury – 90% removal down to 1.0 #/T Btu

These limits have been demonstrated on existing installations. We are hopeful this properly addresses your needs and look forward to any further assistance we can provide.

Best Regards,

Paul Petty
Director, Technology and Applications

cc. Mike Dunseith
Director, Sales and Marketing

Allied Environmental Solutions, Inc.
9730 Patuxent Woods Drive, Suite 100 • Columbia, MD 21046
Tel.: 410.910.5100 • Fax 410.910.5101 • E-Mail: info@allied-env.com

BabcockPower
ENVIRONMENTAL

September 12, 2008

Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Attention: Mr. Carl Weilert

Subject: SO_2 Control Equipment Capabilities

Dear Mr. Weilert:

In response to your questions regarding SO_2 and H_2SO_4 emissions control equipment on boilers with uncontrolled SO_2 emissions ranging from 4.0 to 7.0 lbs/MM Btu we offer the following:

Our Turbosorp® circulating dry scrubbing system can be guaranteed to control SO_2 emissions at the 98% level throughout the range of 4.0 to 7.0 lbs/ MM Btu.

With respect to H_2SO_4 control we can guarantee an outlet emission of 0.005 lbs/MM Btu. This is equivalent to what we understand to be the emissions typically specified for systems utilizing a wet FGD followed by a wet ESP.

I hope this information proves helpful to you. We would welcome an opportunity to meet with you to discuss our technology in greater detail.

Sincerely yours,

Mario Gialanella
JWP

Mario Gialanella
Manager, Business Development

J.S. COOPER AREA TRANSMISSION ANALYSIS

A study of the transmission system in the region surrounding EKPC's J.S. Cooper ("Cooper") generating station has been performed to identify the potential problems with both Cooper units off simultaneously.

Background

Cooper Station is the only fossil-fuel baseload unit in the southern Kentucky region. Hydroelectric units are located at nearby facilities at the Wolf Creek Dam and Laurel Dam. Therefore, these generators are the local generating sources to serve the load in the area. In addition to these generating sources, the E.ON Brown-Alcalde-Pineville 345 kV line provides a source from the north into the region. Also, the E.ON Pineville-Pocket North 500 kV line is another source that can provide some support into the region. However, Wolf Creek Dam, Cooper Station, and the E.ON Alcalde 345-161 kV transformer are the key sources for Casey, Laurel, Lincoln, McCreary, Pulaski, Rockcastle, Russell, and Wayne Counties. Recent studies identified the potential for severe system conditions with reduced generation in the area. These studies were conducted as a result of the potential for substantial reductions in the elevation of Lake Cumberland as a result of concerns about the condition of the Wolf Creek Dam. System conditions were of sufficient concern to recommend measures to address these issues. EKPC constructed a water-cooling system at the J.S. Cooper Station to allow continued normal operation of at least Cooper Unit #2 regardless of lake elevation or water temperature.

EKPC now plans to add environmental controls, including a flue gas desulfurization unit ("scrubber") at Cooper to reduce emissions. The potential for common environmental control equipment for both Cooper generating units that could result in forced outages during a failure has necessitated the need to revisit system conditions in the area with both units off-line simultaneously.

Identification of Area Problems

Power flow analysis was conducted to identify the violations of EKPC and E.ON transmission planning criteria in the area for the 2013-2019 period.

Table 1 provides the list of problems identified for the 2013-2019 period. The date provided is the initial date when a violation for that particular facility is identified. In most cases, the violations increase in severity through the planning horizon.

Table 1 Transmission System Problems for the 2013-2019 Period With Both Cooper Station Generating Units Off					
Season	**Limiting Facility**	**Critical Contingency**	**Identified Value**	**Facility Limit**	**% Loading or Under-voltage**
2013 Summer	Alcalde-Elihu 161 kV Line (EON)	Wolf Creek-Russell County Junction 161 kV Line Out (EKPC)	288.6 MVA	252 MVA	114.5%
2013 Summer	Alcalde-Elihu 161 kV Line (EON)	None	214.7 MVA	202 MVA	106.3%
2013-14 Winter	Alcalde-Elihu 161 kV Line (EON)	Wolf Creek-Russell County Junction 161 kV Line Out (EKPC)	370.1 MVA	330 MVA	112.2%
2013-14 Winter	Hardin County 345-138 kV Transformer (EON)	Hardinsburg-Central Hardin 138 kV Line Out (EON-EKPC)	481.8 MVA	478 MVA	100.8%
2013-14 Winter	Goldbug 13.2 kV Bus Voltage (EKPC)	McCreary County 161-69 kV Transformer (EKPC)	91.4%	92.5%	1.1%
2014 Summer	Coburg-Garlin 69 kV Line (EKPC)	Wolf Creek-Russell County-Jamestown 161 kV Line Out (EKPC)	18.4 MVA	18 MVA	102.2%
2014-15 Winter	Elihu-Ferguson South 69 kV Line (EON)	Elihu-Cooper 161 kV Line Out (EON-EKPC)	129.1 MVA	129 MVA	100.1%
2014-15 Winter	Cabin Hollow 12.5 kV Bus Voltage (EKPC)	Somerset-Cabin Hollow 69 kV Line (EKPC)	92.4%	92.5%	0.1%
2014-15 Winter	Williamsburg South 69 kV Bus Voltage (EON)	Farley 161-69 kV Transformer (EON)	89.9%	90.0%	0.1%
2014-15 Winter	Rockhold 13.2 kV Bus Voltage (EKPC)	Farley-Rockhold 69 kV Line (EON)	92.3%	92.5%	0.2%
2015-16 Winter	Alcalde-Elihu 161 kV Line (EON)	None	299.2 MVA	299 MVA	100.1%

Table 1 **Transmission System Problems for the 2013-2019 Period With Both Cooper Station Generating Units Off**					
2015-16 Winter	South Oak Hill 12.5 kV Bus Voltage (EKPC)	Alcalde-Elihu 161 kV Line (EON)	92.3%	92.5%	0.2%
2015-16 Winter	Hinkle 13.2 kV Bus Voltage (EKPC)	Pineville 345-161 kV Transformer (EON)	92.4%	92.5%	0.1%
2016 Summer	Brush Creek-Carpenter Tap 69 kV Line (EON)	Farley 161-69 kV Transformer Out (EKPC)	41.3 MVA	41 MVA	100.7%
2016-17 Winter	Williamsburg South 69 kV Bus Voltage (E.ON)	Farley-Rockhold 69 kV Line (EON)	89.8%	90.0%	0.2%
2016-17 Winter	Homestead Lane 12.5 kV Bus Voltage (EKPC)	Wayne County-Slat 69 kV Line (EKPC)	92.1%	92.5%	0.4%
2017 Summer	Williamsburg South 69 kV Bus Voltage (E.ON)	Farley-Rockhold 69 kV Line (EON)	89.6%	90.0%	0.4%
2017 Summer	Cumberland Falls 13.2 kV Bus Voltage (EKPC)	Farley-Rockhold 69 kV Line (EON)	92.3%	92.5%	0.2%
2017-18 Winter	Ferguson South-Somerset KU 69 kV Line (EON)	Elihu-Cooper 161 kV Line Out (EON-EKPC)	130.3 MVA	129 MVA	101.0%
2017-18 Winter	South Oak Hill 12.5 kV Bus Voltage (EKPC)	Alcalde 345-161 kV Transformer (EON)	92.1%	92.5%	0.4%
2017-18 Winter	South Oak Hill 12.5 kV Bus Voltage (EKPC)	Brown North-Alcalde-Pineville 345 kV Line (EON)	92.2%	92.5%	0.3%
2018-19 Winter	Campbellsville #2 69 kV Bus Voltage (EKPC)	Taylor County-Campbellsville Tap 69 kV Line (EON)	89.7%	90.0%	0.3%

Most of the problems listed in Table 1 are relatively minor violations of facility limits that can be addressed via line conductor upgrades, reconductors, and/or transmission/distribution capacitor bank additions. The only exceptions are the overloads of the Alcalde-Elihu 161 kV line for the Wolf Creek-Russell County Junction 161 kV line during both summer and winter periods. The loading on the Alcalde-Elihu line for this scenario could approach 115% of the line's emergency rating. This creates a reasonable probability of the line tripping due to the excessive loading.

A cascading outage analysis was performed to determine what the effects of the Alcalde-Elihu 161 kV line tripping could be on the area transmission system. This analysis was performed for the 2013 Summer, 2013-14 Winter, 2018 Summer, and 2018-19 Winter periods to determine how system conditions vary for summer system loads versus winter system loads and how the severity of system conditions changes through the planning period.

The results of this analysis indicate that if the Alcalde-Elihu 161 kV line trips for the scenarios evaluated (Wolf Creek-Russell County Junction 161 kV line outaged with Cooper Units 1 and 2 off), this will create severe overloads and undervoltages across the area during either summer or winter peak conditions. Subsequent trips of transmission facilities and loss of load are likely. The results of the cascading analysis are summarized below.

2013 Summer Cascading Outage Scenario

Starting Point: Cooper Units 1 & 2 Off, Wolf Creek-Russell County Junction 161 kV line out of service
Resulting System Condition: Alcalde-Elihu 161 kV line at 114.5% of emergency rating

Step 1: Trip Alcalde-Elihu 161 kV line
Resulting System Condition: Marion County-Casey County 161 kV line at 120.5% of emergency rating

Step 2: Trip Marion County-Casey County 161 kV line
Resulting System Condition: Denny-Bronston Junction 69 kV line at 141.9% of emergency rating

Step 3: Trip Denny-Bronston Junction 69 kV line
Resulting System Condition: Brush Creek-Carpenter Tap 69 kV line at 108.9% of emergency rating

Step 4: Trip Brush Creek-Carpenter 69 kV line
Resulting System Condition: Farley-Rockhold 69 kV line at 148.7% of emergency rating

Step 5: Trip Farley-Rockhold 69 kV line
Resulting System Condition: Area voltage collapse

Load Shedding Required To Avoid Voltage Collapse: 25 MW for EKPC and 70 MW for EON

2013-14 Winter Cascading Outage Scenario

Starting Point: Cooper Units 1 & 2 Off, Wolf Creek-Russell County Junction 161 kV line out of service
Resulting System Condition: Alcalde-Elihu 161 kV line at 112.2% of emergency rating

Step 1: Trip Alcalde-Elihu 161 kV line
Resulting System Condition: Area voltage collapse

Load Shedding Required To Avoid Voltage Collapse: 50 MW for EKPC and 15 MW for EON

2018 Summer Cascading Outage Scenario

Starting Point: Cooper Units 1 & 2 Off, Wolf Creek-Russell County Junction 161 kV line out of service
Resulting System Condition: Alcalde-Elihu 161 kV line at 117.6% of emergency rating

Step 1: Trip Alcalde-Elihu 161 kV line
Resulting System Condition: Marion County-Casey County 161 kV line at 112.2% of emergency rating

Step 2: Trip Marion County-Casey County 161 kV line
Resulting System Condition: Coburg-Garlin Tap 69 kV line at 213.2% of emergency rating

Step 3: Trip Coburg-Garlin Tap 69 kV line
Resulting System Condition: Denny-Bronston Junction 69 kV line at 129.9% of emergency rating

Step 4: Trip Denny-Bronston Junction 69 kV line
Resulting System Condition: Zula Junction-Upchurch Tap 69 kV line at 134.7% of emergency rating

Step 5: Trip Zula Junction-Upchurch Tap 69 kV line
Resulting System Condition: Wofford-Cumberland Falls Tap 69 kV line at 125.8% of emergency rating

Step 6: Trip Wofford-Cumberland Falls Tap 69 kV line
Resulting System Condition: Summershade 161-69 kV transformer at 117.3% of emergency rating

Step 7: Trip Summershade 161-69 kV transformer
Resulting System Condition: Area voltage collapse

Load Shedding Required To Avoid Voltage Collapse: 70 MW for EKPC and 10 MW for EON

2018-19 Winter Cascading Outage Scenario

Starting Point: Cooper Units 1 & 2 Off, Wolf Creek-Russell County Junction 161 kV line out of service
Resulting System Condition: Alcalde-Elihu 161 kV line at 120.8% of emergency rating

Step 1: Trip Alcalde-Elihu 161 kV line
Resulting System Condition: Area voltage collapse

Load Shedding Required To Avoid Voltage Collapse: 90 MW for EKPC and 15 MW for EON

Therefore, the load shedding that would be required to avoid widespread voltage collapse in the area ranges from 25 MW to 90 MW for EKPC and from 10 MW to 70 MW for EON. This load shedding would need to be automated to occur immediately for a trip of the Alcalde-Elihu 161 kV line, or would need to occur prior to the Wolf Creek-Russell County Junction 161 kV line outage when system conditions warrant. If proactive load shedding is not performed, the potential would exist for a much more extensive loss of load as a result of the cascading outages that could occur in the area. As much as approximately 500 MW of EKPC load and 200 MW of E.ON load could be dropped for these extreme scenarios.

Alternative Solutions to System Problems

The primary problem to be addressed is the overload of the Alcalde-Elihu 161 kV line, which could approach 15% over the emergency rating of the line. The limit for this line is the maximum rating of the 556.5 KCM ACSR conductor in the line. This problem can be addressed by replacing the line conductor with larger conductor (795 KCM ACSR or larger). The other problems identified in Table 1 are relatively minor problems that can be addressed by upgrading conductors and/or terminal facilities of the listed overloaded facilities as well as installing local 69 kV capacitor banks to address the low voltage problems.

Further analysis will be performed to identify specific solutions and to develop recommendations. The solutions to be considered will include the use of load shedding schemes, generation re-dispatch, and transmission system upgrades.

Conclusions

The study results documented here highlight the importance of the Cooper Station generating units for the area. It is critical to minimize the opportunities for single-mode failures of equipment at Cooper Station to trip both units offline simultaneously. Future transmission system modifications or additions will be needed in the area, but will not eliminate the need for this generation dispatch consideration.

Further recommendations will be made to address system problems in the area after analysis of transmission alternatives is completed.

EKPC
Cooper Retrofit Project
Fuels Screening Summary
August 28, 2008

Objective:

To identify and narrow a list of candidate fuels for a detailed boiler impact study and the engineering considerations necessary for the scoping and preliminary design phase of the Cooper Retrofit Project (CRP).

Background:

EKPC is required to install and operate pollution control equipment at the John Sherman Cooper Power Station, in Burnside, Kentucky. This equipment will be installed in order to comply with current environmental requirements including a Consent Decree negotiated between EKPC and EPA for Unit #2. Modifications to be made to the plant as part of this initiative will allow a change in fuel specifications, and potentially, the use of less costly fuel than is utilized at the plant currently. Key fuel characteristics to consider in this phase of the project are projected price, and quality in terms of elemental content/performance. Other important factors like quantity available, method and cost of delivery, source and location of fuel, production and delivery capability, and security of supply, change with market conditions over time and are evaluated in more detail when fuel purchase evaluations are made. The evaluation must focus on minimized cost and optimized fuel flexibility as considerations are made about the modification and future operation of the plant.

A market evaluation was performed to identify available fuels, and select those that should beused to establish design parameters and evaluate boiler performance. Although no reliable market is currently observable in this area for biomass fuels, they will be included for boiler impact evaluation as a possible fuel additive, should the circumstances change, regarding adequate local supply.

Screening Process:

The 19 coal types initially identified for the screening process were chosen as representative fuels from different coal basins that could economically, efficiently, and safely power the boiler(s) at Cooper Station while maximizing fuel flexibility.

- Price Ranking

Energy Ventures Analysis, Inc. (EVA) had previously been commissioned by EKPC to provide price forecast for 19 types of coal, natural gas, fuel oil, and emissions through 2030. The coal forecast was to be based on BTU/lb, #SO_2/MMBtu, and % Ash. For the CRP, EVA provided projected coal prices for the 19 coal types in $/MMBtu through 2030 (FOB mine). EKPC estimated transportation costs to Cooper Station using a combination of actual transportation costs combined with projections based on available market information to determine a delivered cost (Exhibit 1). Because of the defined schedule for the CRP, the coal types were ranked based on data for the first year of commercial operation (2012).

EKPC routinely uses project specific engagements and subscriptions to FUELCAST, COALCAST, and eCAST services from Energy Ventures Analysis, Inc. (EVA). These services are used throughout the energy and environmental industries for short and long-term price and market forecasts. EVA has been providing the energy industry with expert advice for the past 25 years. The company specializes in energy and environmental market analysis and forecasting for natural gas, coal, electricity, oil, NO_x, SO_2, and CO_2, as well as project analysis, including project proformas and financial evaluations for existing and proposed power plants, coal mines and coal companies, natural gas storage projects, and other energy projects. EVA's primary expertise is in energy forecasts. Their coal services have been performed for many major coal companies, electric utilities and other consumers like railroad companies, equipment manufacturers and government agencies.

Cooper Station's Unit 2 currently has clearly defined coal specification requirements for operating the boiler at full load. The boiler has a minimum BTU/lb specification of 11,500 and maximum Ash specification of 12%. Three of the 19 coal types being evaluated were quickly eliminated because they failed to meet both the BTU/lb and Ash specification. They were CAPP-Raw, ILB-WK, and NAPP-Pitts Raw. A fourth coal, PRB, was eliminated because it was significantly more expensive than the other candidates due to the freight costs. Consequently the list of 19 coal types was reduced to 15.

- *Elemental Characteristics*

EKPC's Fuel and Emissions group provided the elemental analysis for 18 specific coals, corresponding to the 15 remaining coal types, along with the elemental analysis for wood and switchgrass as potential biomass co-firing additives. to Babcock and Wilcox (B&W), who were under contract to the Burns & McDonnell (B&M), the Owner's Engineer, to perform boiler performance evaluations. There were 14 coals identified by B&W as viable candidates for boiler evaluation (Exhibit 2). In order to make that evaluation effort more manageable, the fuels were grouped based on their similarities by B&M, with concurrence by EKPC, as follows.

Illinois Basin Group
Williams – Illinois #6
James River – Indiana #5
Highland #9

Central Appalachian Group A (High Sulfur)
Middle 8 Hazard
Hazard 8 Split 2
Trinity/Little Elk Mining

Central Appalachian Group B (Mid-Range Sulfur)
Sample S-667
Sample S-671
Sample S-673
Sample S-674-1

Central Appalachian Group C (Low Sulfur)
Dale Gatliff 2116
Dale Trinity 2117

Northern Appalachian Group (Compliance Coal)
Daron #8
Daron #9

EKPC is currently using coals that are representative of those in the Central Appalachian Groups B & C. Because of our extensive experience and familiarity with long term performance data for coals in these groups and their effects on specific boilers, it was decided that a cursory assessment of potential boiler and downstream affects would be adequate to incorporate these coals into the final pool of accepted candidates.

In order to reduce repetition, and minimize the time required to perform detailed boiler performance analysis on the remaining fuels, it was decided that a representative coal from each group would be used as a proxy for the worst case for boiler operation. This effectively reduced the number of full boiler impact evaluations conducted by B&W to 3 fuels plus the biomass additives.

Consequently, the fuel analysis for both of these materials was also provided to B&M and B&W for boiler evaluation. Wood and switchgrass are the most reasonable bio-mass fuels to consider for Cooper because of market and operational considerations. Woody biomass is plentiful in the geographic area around Cooper Station. While there are small industries in the area that are currently using wood waste as feedstock such as charcoal and pellet manufacturers, there are currently no paper mills or other comparable facilities in this area with a large appetite for wood waste as a fuel supply. Likewise, there are no Ethanol producers, or other significant competitors for switchgrass supply, although no reliable supply exists in the region. Operationally, wood and switchgrass would require special transportation, storage, handling, and processing at the plant. Boiler modifications may be necessary if large volumes of these supplementary fuels are used over the long-term.

- Other Considerations

Fuel delivery for the Cooper site must be carefully considered. Long distance truck delivery may not be economical, therefore Norfolk Southern's rail deliveries must be taken into consideration. Installation of a rotary coal unloader or other acceptable unloading facility may be needed,and expansion of the railsiding from 50 cars to 100-150 cars may be appropriate to accommodate the delivery of future coals.

Understanding coal reserves from different coal regions is also paramount when considering long-term fuel supplies. With the coal reserves in CAPP depleting, the coal that is available and economical today could well be different in the future. It is generally believed that the ILB coal reserves are adequate for many years to come and in the recent coal market changes, ILB prices increased, but not to the degree of CAPP prices. EKPC believes that CAPP coal is going to be more susceptible to the export market because of its geographical location making easy access to the East Coast seaports.

Conclusions and Recommendations

For design of the required pollution control equipment, EKPC and B&M selected a design coal (Daron #8) from the list of acceptable candidates for it's characteristics related to Sulfur and Ash. Using this "outer boundary" will make provisions for appropriate environmental performance for the range of coals deemed acceptable in the screening process.

Likewise, those "worst case" coals from each group were used in the boiler analysis. In a proprietary and confidential report, B&W made recommendations related to the slagging, fouling and erosive tendencies of the submitted coals. In the Northern Appalachian Coal, although Daron #8 was used as the pollution control design "worst case", Daron #9 was used to simulate the "worst case" for boiler slagging due to it's lower fusion temperature.

This approach is based on the premise that if the new equipment and processes work effectively with the "design/worst case" coals, the other economically viable fuels in the list and the fuel blends made from them, will also be acceptable from both the environmental and operational performance perspectives. Coals are currently blended at Cooper to achieve optimum performance and cost effectiveness, and this will likely continue into the future, after the addition of the pollution control equipment. Although the "design" coal may never actually be used for production at the Cooper Generating Station, it represents the appropriate practical limits of the equipment and process design for fuel use.

The information and conclusions developed during the screening process between EKPC and B&M, with technical support from B&W, are to be incorporated into the preliminary design and scope for the project. Further assessment for potential boiler modifications may be made as a part of detailed design.

Space allotment for an improved rail car unloader and expansion of the on-site rail system to allow for larger train deliveries should be made in the site plan development for the possibility of using future coals, should market conditions warrant.

Attachments:

JRT Exhibit 3 – Attachment A – Market Comparison of Fuels
JRT Exhibit 3 – Attachment B – Individual Fuel Analysis Reports

ATTACHMENT A

Market Comparison of Fuels

Delivered $/MMBtu basis

						Actual	Forecast (Nominal $/ton)																						
Freight	Coal Type	FOB Point	Btu/lb	#SO2/MMBtu	Ash (%)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

						Actual	Forecast (Nominal $/ton)																						
Freight	Coal Type	FOB Point	Btu/lb	#SO2/MMBtu	Ash (%)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	CAPP-Raw	Truck	9300	2.2	32		4.253	4.174	3.631	3.247	2.901	2.841	2.917	2.983	3.072	3.16	3.238	3.323	3.408	3.498	3.588	3.681	3.774	3.873	3.974	4.08	4.187	4.297	4.41
	ILB-WK	Green Rvr	10500	7	20		3.973	3.86	3.413	3.186	2.96	2.92	2.981	3.036	3.103	3.167	3.225	3.29	3.354	3.42	3.487	3.556	3.623	3.694	3.766	3.841	3.916	3.992	4.07
	CAPP-Manchester	Truck	12000	4.5	11		4.541	4.46	3.828	3.38	2.97	2.886	2.968	3.025	3.132	3.235	3.311	3.401	3.493	3.588	3.682	3.781	3.874	3.977	4.085	4.2	4.313	4.429	4.55
	ILB-WK	Green Rvr	11500	6	10		4.049	3.927	3.461	3.223	2.987	2.947	3.009	3.068	3.133	3.198	3.26	3.326	3.392	3.46	3.529	3.599	3.67	3.743	3.817	3.894	3.97	4.049	4.13
	CAPP-Hazard	Truck	12000	4.5	11		4.607	4.528	3.896	3.448	3.039	2.957	3.039	3.098	3.205	3.31	3.387	3.478	3.57	3.667	3.762	3.862	3.956	4.06	4.17	4.285	4.4	4.518	4.64
	CAPP-Manchester	Truck	12000	2.8	11		4.62	4.537	3.907	3.46	3.053	2.975	3.057	3.122	3.226	3.329	3.41	3.503	3.597	3.694	3.791	3.893	3.992	4.098	4.209	4.325	4.441	4.561	4.684
	CAPP-Hazard	Truck	12000	2.8	11		4.686	4.604	3.975	3.529	3.123	3.045	3.129	3.195	3.299	3.403	3.486	3.579	3.674	3.773	3.871	3.974	4.074	4.182	4.294	4.411	4.528	4.649	4.774
	NAPP-Ohio Strip	Ohio R	11500	7	10		4.499	4.373	3.982	3.527	3.153	3.193	3.26	3.315	3.401	3.482	3.546	3.622	3.701	3.784	3.866	3.952	4.033	4.121	4.213	4.309	4.406	4.503	4.604
	CAPP-Hazard	Truck	12000	2.2	11		4.73	4.637	4.009	3.564	3.162	3.09	3.175	3.248	3.348	3.446	3.534	3.629	3.725	3.825	3.926	4.031	4.135	4.245	4.36	4.478	4.598	4.72	4.848
	CAPP-Hazard	Truck	12000	1.6	11		4.978	4.788	4.08	3.633	3.232	3.168	3.256	3.344	3.435	3.526	3.62	3.718	3.817	3.92	4.025	4.134	4.246	4.36	4.478	4.599	4.723	4.851	4.981
	CAPP-Hazard	Truck	12000	1.2	11		5.143	4.94	4.206	3.751	3.343	3.284	3.372	3.473	3.563	3.654	3.758	3.86	3.964	4.07	4.182	4.295	4.418	4.538	4.661	4.786	4.916	5.05	5.186
	NAPP-Pitts VH	Ohio R	12500	6	10		4.757	4.62	4.212	3.74	3.354	3.402	3.475	3.542	3.626	3.708	3.784	3.866	3.953	4.042	4.132	4.225	4.317	4.414	4.513	4.616	4.719	4.825	4.935
	CAPP-Pike-Uncrushed	Truck	12000	2.8	11		5.046	4.969	4.346	3.905	3.505	3.433	3.523	3.594	3.705	3.815	3.904	4.003	4.104	4.209	4.314	4.423	4.53	4.645	4.764	4.888	5.013	5.14	5.273
	CAPP-Pike-Uncrushed	Truck	12000	2.2	11		5.09	5.002	4.379	3.94	3.544	3.478	3.568	3.648	3.753	3.858	3.951	4.053	4.155	4.262	4.369	4.48	4.591	4.709	4.83	4.955	5.082	5.212	5.346
	CAPP-Pike-Uncrushed	Truck	12000	1.6	11		5.338	5.153	4.451	4.01	3.614	3.555	3.65	3.744	3.84	3.938	4.038	4.142	4.248	4.356	4.469	4.583	4.702	4.824	4.948	5.076	5.208	5.342	5.48
	NAPP-Pitts Raw	Ohio R	9500	7.5	30		4.922	4.803	4.428	3.989	3.634	3.688	3.764	3.829	3.919	4.006	4.082	4.166	4.253	4.345	4.436	4.531	4.623	4.721	4.822	4.926	5.032	5.139	5.25
	CAPP-Pike-Uncrushed	Truck	12000	1.2	11		5.483	5.285	4.556	4.106	3.704	3.65	3.743	3.85	3.945	4.042	4.152	4.259	4.369	4.481	4.599	4.718	4.848	4.974	5.104	5.235	5.372	5.513	5.656
	NAPP-Pitt HS	Mon R	13000	3.8	8		5.788	5.441	4.783	4.193	3.795	3.851	3.931	4.015	4.098	4.183	4.27	4.36	4.455	4.552	4.652	4.753	4.859	4.965	5.074	5.185	5.299	5.415	5.534
	PRB	Rail	8800	0.8	5		3.623	3.655	3.805	3.973	4.094	4.172	4.252	4.332	4.42	4.505	4.591	4.68	4.77	4.863	4.957	5.055	5.155	5.257	5.361	5.469	5.579	5.692	5.807

Sorted by least price for 2012

Freight	Coal Type	FOB Point	Btu/lb	#SO2/MMBtu	Ash (%)	Actual	Forecast (Nominal $/ton)																					
						2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	CAPP-Pike-Uncrushed	Truck	12,000	1.2	11.0	42.37	109.26	104.18	86.34	75.19	65.19	63.53	65.41	67.61	69.51	71.46	73.72	75.90	78.15	80.45	82.87	85.32	88.00	90.61	93.29	96.01	98.85	101.77	104.75
22	Freight						22.33	22.66	23.00	23.35	23.70	24.06	24.42	24.79	25.16	25.54	25.92	26.31	26.70	27.10	27.51	27.92	28.34	28.77	29.20	29.64	30.08	30.53	30.99
	Deliv/ton						131.59	126.84	109.34	98.54	88.89	87.59	89.83	92.40	94.67	97.00	99.64	102.21	104.85	107.55	110.38	113.24	116.34	119.38	122.49	125.65	128.93	132.30	135.74
	Deliv/MMBtu						5.483	5.285	4.556	4.106	3.704	3.650	3.743	3.850	3.945	4.042	4.152	4.259	4.369	4.481	4.599	4.718	4.848	4.974	5.104	5.235	5.372	5.513	5.656
	CAPP-Hazard	Truck	12,000	1.2	11.0	43.33	110.24	105.17	87.35	76.22	66.23	64.60	66.49	68.71	70.63	72.60	74.88	77.08	79.35	81.66	84.11	86.58	89.27	91.91	94.61	97.35	100.20	103.15	106.14
13	Freight						13.20	13.40	13.60	13.80	14.01	14.22	14.43	14.65	14.87	15.09	15.32	15.55	15.78	16.02	16.26	16.50	16.75	17.00	17.26	17.52	17.78	18.05	18.32
	Deliv/ton						123.44	118.57	100.95	90.02	80.24	78.82	80.92	83.36	85.50	87.69	90.20	92.63	95.13	97.68	100.37	103.08	106.02	108.91	111.87	114.87	117.98	121.20	124.46
	Deliv/MMBtu						5.143	4.940	4.206	3.751	3.343	3.284	3.372	3.473	3.563	3.654	3.758	3.860	3.964	4.070	4.182	4.295	4.418	4.538	4.661	4.786	4.916	5.050	5.186
	CAPP-Pike-Uncrushed	Truck	12,000	1.6	11.0	39.94	105.78	101.00	83.82	72.88	63.03	61.27	63.17	65.06	67.00	68.97	70.99	73.09	75.24	77.45	79.74	82.08	84.51	87.00	89.56	92.19	94.90	97.68	100.54
22	Freight						22.33	22.66	23.00	23.35	23.70	24.06	24.42	24.79	25.16	25.54	25.92	26.31	26.70	27.10	27.51	27.92	28.34	28.77	29.20	29.64	30.08	30.53	30.99
	Deliv/ton						128.11	123.66	106.82	96.23	86.73	85.33	87.59	89.85	92.16	94.51	96.91	99.40	101.94	104.55	107.25	110.00	112.85	115.77	118.76	121.83	124.98	128.21	131.53
	Deliv/MMBtu						5.338	5.153	4.451	4.010	3.614	3.555	3.650	3.744	3.840	3.938	4.038	4.142	4.248	4.356	4.469	4.583	4.702	4.824	4.948	5.076	5.208	5.342	5.480
	CAPP-Hazard	Truck	12,000	1.6	11.0	40.42	106.27	101.50	84.32	73.39	63.55	61.80	63.71	65.61	67.56	69.54	71.57	73.68	75.83	78.06	80.35	82.71	85.15	87.65	90.22	92.86	95.58	98.37	101.23
13	Freight						13.20	13.40	13.60	13.80	14.01	14.22	14.43	14.65	14.87	15.09	15.32	15.55	15.78	16.02	16.26	16.50	16.75	17.00	17.26	17.52	17.78	18.05	18.32
	Deliv/ton						119.47	114.90	97.92	87.19	77.56	76.02	78.14	80.26	82.43	84.63	86.89	89.23	91.61	94.08	96.61	99.21	101.90	104.65	107.48	110.38	113.36	116.42	119.55
	Deliv/MMBtu						4.978	4.788	4.080	3.633	3.232	3.168	3.256	3.344	3.435	3.526	3.620	3.718	3.817	3.920	4.025	4.134	4.246	4.360	4.478	4.599	4.723	4.851	4.981
	CAPP-Pike-Uncrushed	Truck	12,000	2.2	11.0	36.42	99.84	97.39	82.10	71.22	61.35	59.40	61.22	62.76	64.92	67.06	68.91	70.95	73.02	75.18	77.34	79.61	81.85	84.24	86.71	89.28	91.88	94.56	97.32
22	Freight						22.33	22.66	23.00	23.35	23.70	24.06	24.42	24.79	25.16	25.54	25.92	26.31	26.70	27.10	27.51	27.92	28.34	28.77	29.20	29.64	30.08	30.53	30.99
	Deliv/ton						122.17	120.05	105.10	94.57	85.05	83.46	85.64	87.55	90.08	92.60	94.83	97.26	99.72	102.28	104.85	107.53	110.19	113.01	115.91	118.92	121.96	125.09	128.31
	Deliv/MMBtu						5.090	5.002	4.379	3.940	3.544	3.478	3.568	3.648	3.753	3.858	3.951	4.053	4.155	4.262	4.369	4.480	4.591	4.709	4.830	4.955	5.082	5.212	5.346
	CAPP-Hazard	Truck	12,000	2.2	11.0	36.90	100.33	97.89	82.61	71.73	61.87	59.94	61.76	63.31	65.48	67.62	69.49	71.54	73.61	75.79	77.96	80.24	82.49	84.89	87.37	89.94	92.56	95.24	98.02
13	Freight						13.20	13.40	13.60	13.80	14.01	14.22	14.43	14.65	14.87	15.09	15.32	15.55	15.78	16.02	16.26	16.50	16.75	17.00	17.26	17.52	17.78	18.05	18.32
	Deliv/ton						113.53	111.29	96.21	85.53	75.88	74.16	76.19	77.96	80.35	82.71	84.81	87.09	89.39	91.81	94.22	96.74	99.24	101.89	104.63	107.46	110.34	113.29	116.34
	Deliv/MMBtu						4.730	4.637	4.009	3.564	3.162	3.090	3.175	3.248	3.348	3.446	3.534	3.629	3.725	3.825	3.926	4.031	4.135	4.245	4.360	4.478	4.598	4.720	4.848
	CAPP-Pike-Uncrushed	Truck	12,000	2.8	11.0	34.45	98.77	96.60	81.30	70.37	60.41	58.33	60.12	61.47	63.75	66.01	67.77	69.77	71.80	73.91	76.03	78.24	80.38	82.71	85.13	87.67	90.22	92.84	95.56
22	Freight						22.33	22.66	23.00	23.35	23.70	24.06	24.42	24.79	25.16	25.54	25.92	26.31	26.70	27.10	27.51	27.92	28.34	28.77	29.20	29.64	30.08	30.53	30.99
	Deliv/ton						121.10	119.26	104.30	93.72	84.11	82.39	84.54	86.26	88.91	91.55	93.69	96.08	98.50	101.01	103.54	106.16	108.72	111.48	114.33	117.31	120.30	123.37	126.55
	Deliv/MMBtu						5.046	4.969	4.346	3.905	3.505	3.433	3.523	3.594	3.705	3.815	3.904	4.003	4.104	4.209	4.314	4.423	4.530	4.645	4.764	4.888	5.013	5.140	5.273
	CAPP-Hazard	Truck	12,000	2.8	11.0	34.93	99.26	97.09	81.80	70.89	60.93	58.86	60.66	62.02	64.31	66.58	68.35	70.35	72.39	74.52	76.65	78.87	81.02	83.36	85.79	88.34	90.90	93.53	96.25
13	Freight						13.20	13.40	13.60	13.80	14.01	14.22	14.43	14.65	14.87	15.09	15.32	15.55	15.78	16.02	16.26	16.50	16.75	17.00	17.26	17.52	17.78	18.05	18.32
	Deliv/ton						112.46	110.49	95.40	84.69	74.94	73.08	75.09	76.67	79.18	81.67	83.67	85.90	88.17	90.54	92.91	95.37	97.77	100.36	103.05	105.86	108.68	111.58	114.57
	Deliv/MMBtu						4.686	4.604	3.975	3.529	3.123	3.045	3.129	3.195	3.299	3.403	3.486	3.579	3.674	3.773	3.871	3.974	4.074	4.182	4.294	4.411	4.528	4.649	4.774
	CAPP-Manchester	Truck	12,000	2.8	11.0	36.37	100.73	98.59	83.32	72.43	62.50	60.46	62.28	63.67	65.99	68.29	70.08	72.12	74.19	76.34	78.50	80.75	82.93	85.30	87.76	90.34	92.93	95.60	98.35
10	Freight						10.15	10.30	10.45	10.61	10.77	10.93	11.09	11.26	11.43	11.60	11.77	11.95	12.13	12.31	12.49	12.68	12.87	13.06	13.26	13.46	13.66	13.86	14.07
	Deliv/ton						110.88	108.89	93.77	83.04	73.27	71.39	73.37	74.93	77.42	79.89	81.85	84.07	86.32	88.65	90.99	93.43	95.80	98.36	101.02	103.80	106.59	109.46	112.42
	Deliv/MMBtu						4.620	4.537	3.907	3.460	3.053	2.975	3.057	3.122	3.226	3.329	3.410	3.503	3.597	3.694	3.791	3.893	3.992	4.098	4.209	4.325	4.441	4.561	4.684
	CAPP-Raw	Truck	9,300	2.2	32.0	23.30	65.91	64.24	53.94	46.60	39.95	38.62	39.82	40.83	42.26	43.68	44.90	46.25	47.60	49.04	50.47	51.97	53.45	55.03	56.66	58.36	60.09	61.87	63.70
13	Freight						13.20	13.40	13.60	13.80	14.01	14.22	14.43	14.65	14.87	15.09	15.32	15.55	15.78	16.02	16.26	16.50	16.75	17.00	17.26	17.52	17.78	18.05	18.32
	Deliv/ton						79.11	77.64	67.54	60.40	53.96	52.84	54.25	55.48	57.13	58.77	60.22	61.80	63.38	65.06	66.73	68.47	70.20	72.03	73.92	75.88	77.87	79.92	82.02
	Deliv/MMBtu						4.253	4.174	3.631	3.247	2.901	2.841	2.917	2.983	3.072	3.160	3.238	3.323	3.408	3.498	3.588	3.681	3.774	3.873	3.974	4.080	4.187	4.297	4.410

Freight	Coal Type	FOB Point	Btu/lb	#SO2/MMBtu	Ash (%)	Actual 2007	Forecast (Nominal $/ton) 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	PRB	Rail	8,800	0.8	5.0	10.05	13.01	12.81	14.68	16.87	18.19	18.75	19.35	19.93	20.63	21.26	21.91	22.59	23.28	24.01	24.75	25.52	26.33	27.16	28.02	28.92	29.84	30.80	31.79
50	Freight						50.75	51.51	52.28	53.06	53.86	54.67	55.49	56.32	57.16	58.02	58.89	59.77	60.67	61.58	62.50	63.44	64.39	65.36	66.34	67.34	68.35	69.38	70.42
	Deliv/ton						63.76	64.32	66.96	69.93	72.05	73.42	74.84	76.25	77.79	79.28	80.80	82.36	83.95	85.59	87.25	88.96	90.72	92.52	94.36	96.26	98.19	100.18	102.21
	Deliv/MMBtu						3.623	3.655	3.805	3.973	4.094	4.172	4.252	4.332	4.420	4.505	4.591	4.680	4.770	4.863	4.957	5.055	5.155	5.257	5.361	5.469	5.579	5.692	5.807
	ILB-WK	Green Rvr	11,500	6.0	10.0	31.90	68.76	65.59	54.50	48.66	42.85	41.52	42.57	43.53	44.61	45.69	46.70	47.79	48.89	50.01	51.15	52.32	53.49	54.70	55.95	57.23	58.51	59.83	61.18
24	Freight						24.36	24.73	25.10	25.48	25.86	26.25	26.64	27.04	27.45	27.86	28.28	28.70	29.13	29.57	30.01	30.46	30.92	31.38	31.85	32.33	32.81	33.30	33.80
	Deliv/ton						93.12	90.32	79.60	74.14	68.71	67.77	69.21	70.57	72.06	73.55	74.98	76.49	78.02	79.58	81.16	82.78	84.41	86.08	87.80	89.56	91.32	93.13	94.98
	Deliv/MMBtu						4.049	3.927	3.461	3.223	2.987	2.947	3.009	3.068	3.133	3.198	3.260	3.326	3.392	3.460	3.529	3.599	3.670	3.743	3.817	3.894	3.970	4.049	4.130
	ILB-WK	Green Rvr	10,500	7.0	20.0	26.66	59.08	56.33	46.58	41.43	36.30	35.07	35.97	36.72	37.71	38.65	39.45	40.38	41.30	42.26	43.22	44.21	45.16	46.19	47.24	48.33	49.43	50.54	51.67
24	Freight						24.36	24.73	25.10	25.48	25.86	26.25	26.64	27.04	27.45	27.86	28.28	28.70	29.13	29.57	30.01	30.46	30.92	31.38	31.85	32.33	32.81	33.30	33.80
	Deliv/ton						83.44	81.06	71.68	66.91	62.16	61.32	62.61	63.76	65.16	66.51	67.73	69.08	70.43	71.83	73.23	74.67	76.08	77.57	79.09	80.66	82.24	83.84	85.47
	Deliv/MMBtu						3.973	3.860	3.413	3.186	2.960	2.920	2.981	3.036	3.103	3.167	3.225	3.290	3.354	3.420	3.487	3.556	3.623	3.694	3.766	3.841	3.916	3.992	4.070
	NAPP-Pitts VH	Ohio R	12,500	6.0	10.0	39.60	83.40	79.43	68.71	56.34	46.13	46.77	48.02	49.13	50.63	52.09	53.38	54.81	56.34	57.93	59.53	61.19	62.82	64.56	66.36	68.22	70.10	72.03	74.04
35	Freight						35.53	36.06	36.60	37.15	37.71	38.28	38.85	39.43	40.02	40.62	41.23	41.85	42.48	43.12	43.77	44.43	45.10	45.78	46.47	47.17	47.88	48.60	49.33
	Deliv/ton						118.93	115.49	105.31	93.49	83.84	85.05	86.87	88.56	90.65	92.71	94.61	96.66	98.82	101.05	103.30	105.62	107.92	110.34	112.83	115.39	117.98	120.63	123.37
	Deliv/MMBtu						4.757	4.620	4.212	3.740	3.354	3.402	3.475	3.542	3.626	3.708	3.784	3.866	3.953	4.042	4.132	4.225	4.317	4.414	4.513	4.616	4.719	4.825	4.935
	NAPP-Pitts Raw	Ohio R	9,500	7.5	30.0	26.69	57.99	55.20	47.54	38.65	31.34	31.79	32.66	33.33	34.45	35.49	36.32	37.30	38.33	39.43	40.51	41.65	42.73	43.91	45.14	46.43	47.73	49.05	50.42
35	Freight						35.53	36.06	36.60	37.15	37.71	38.28	38.85	39.43	40.02	40.62	41.23	41.85	42.48	43.12	43.77	44.43	45.10	45.78	46.47	47.17	47.88	48.60	49.33
	Deliv/ton						93.52	91.26	84.14	75.80	69.05	70.07	71.51	72.76	74.47	76.11	77.55	79.15	80.81	82.55	84.28	86.08	87.83	89.69	91.61	93.60	95.61	97.65	99.75
	Deliv/MMBtu						4.922	4.803	4.428	3.989	3.634	3.688	3.764	3.829	3.919	4.006	4.082	4.166	4.253	4.345	4.436	4.531	4.623	4.721	4.822	4.926	5.032	5.139	5.250
	NAPP-Ohio Strip	Ohio R	11,500	7.0	10.0	29.08	67.94	64.53	54.98	43.97	34.81	35.16	36.14	36.82	38.21	39.46	40.32	41.45	42.65	43.92	45.15	46.46	47.65	49.00	50.43	51.94	53.45	54.97	56.57
35	Freight						35.53	36.06	36.60	37.15	37.71	38.28	38.85	39.43	40.02	40.62	41.23	41.85	42.48	43.12	43.77	44.43	45.10	45.78	46.47	47.17	47.88	48.60	49.33
	Deliv/ton						103.47	100.59	91.58	81.12	72.52	73.44	74.99	76.25	78.23	80.08	81.55	83.30	85.13	87.04	88.92	90.89	92.75	94.78	96.90	99.11	101.33	103.57	105.90
	Deliv/MMBtu						4.499	4.373	3.982	3.527	3.153	3.193	3.260	3.315	3.401	3.482	3.546	3.622	3.701	3.784	3.866	3.952	4.033	4.121	4.213	4.309	4.406	4.503	4.604
	NAPP-Pitt HS	Mon R	13,000	3.8	8.0	46.08	104.81	95.10	77.29	61.23	50.16	50.90	52.24	53.67	55.07	56.50	58.00	59.54	61.19	62.90	64.67	66.46	68.34	70.24	72.19	74.18	76.22	78.32	80.47
45	Freight						45.68	46.37	47.07	47.78	48.50	49.23	49.97	50.72	51.48	52.25	53.03	53.83	54.64	55.46	56.29	57.13	57.99	58.86	59.74	60.64	61.55	62.47	63.41
	Deliv/ton						150.49	141.47	124.36	109.01	98.66	100.13	102.21	104.39	106.55	108.75	111.03	113.37	115.83	118.36	120.96	123.59	126.33	129.10	131.93	134.82	137.77	140.79	143.88
	Deliv/MMBtu						5.788	5.441	4.783	4.193	3.795	3.851	3.931	4.015	4.098	4.183	4.270	4.360	4.455	4.552	4.652	4.753	4.859	4.965	5.074	5.185	5.299	5.415	5.534
	CAPP-Hazard	Truck	12,000	4.5	11.0	32.79	97.36	95.26	79.91	68.96	58.93	56.74	58.50	59.69	62.06	64.34	65.96	67.92	69.89	71.98	74.02	76.18	78.20	80.45	82.82	85.32	87.83	90.37	93.03
13	Freight						13.20	13.40	13.60	13.80	14.01	14.22	14.43	14.65	14.87	15.09	15.32	15.55	15.78	16.02	16.26	16.50	16.75	17.00	17.26	17.52	17.78	18.05	18.32
	Deliv/ton						110.56	108.66	93.51	82.76	72.94	70.96	72.93	74.34	76.93	79.43	81.28	83.47	85.67	88.00	90.28	92.68	94.95	97.45	100.08	102.84	105.61	108.42	111.35
	Deliv/MMBtu						4.607	4.528	3.896	3.448	3.039	2.957	3.039	3.098	3.205	3.310	3.387	3.478	3.570	3.667	3.762	3.862	3.956	4.060	4.170	4.285	4.400	4.518	4.640
	CAPP-Manchester	Truck	12,000	4.5	11.0	34.23	98.83	96.75	81.43	70.50	60.50	58.34	60.13	61.35	63.74	66.04	67.70	69.68	71.69	73.80	75.87	78.06	80.11	82.39	84.79	87.33	89.86	92.43	95.13
10	Freight						10.15	10.30	10.45	10.61	10.77	10.93	11.09	11.26	11.43	11.60	11.77	11.95	12.13	12.31	12.49	12.68	12.87	13.06	13.26	13.46	13.66	13.86	14.07
	Deliv/ton						108.98	107.05	91.88	81.11	71.27	69.27	71.22	72.61	75.17	77.64	79.47	81.63	83.82	86.11	88.36	90.74	92.98	95.45	93.05	100.79	103.52	106.29	109.20
	Deliv/MMBtu						4.541	4.460	3.828	3.380	2.970	2.886	2.968	3.025	3.132	3.235	3.311	3.401	3.493	3.588	3.682	3.781	3.874	3.977	4.085	4.200	4.313	4.429	4.550

Delivered cost on each coal

ATTACHMENT B

Individual Fuel Analysis Reports

Proximate Analysis
Ultimate Analysis
Ash Mineral Analysis
Other Properties
Ash Fusion Temperatures
Sulfur Forms
Metals

Williamson Energy, LLC
P.O. Box 300
Johnston City, Illinois

Date Sampled: December 13, 2006

Quality Data - Pond Creek #1 Mine (3 Train Composite of Dec. trains 73491-05, 73941-07, 73941-10)
Illinois #6 Seam
High Volatile Steam Coal

Analysis Performed by:
Precesion Testing Laboratory
P.O. Box 1985
Beckley, WV 25802

PROXIMATE ANALYSIS

	As Received	Dry
Total Moisture	10.97%	-
Volatile Matter	35.84%	40.26%
Ash	8.22%	9.23%
Fixed Carbon	44.97%	50.51%
Sulfur	2.81%	3.16%
Lbs/MMBTU SO2	4.77	
BTU	11,801	13,255
MAF BTU		14,603

ULTIMATE ANALYSIS

	As Received	Dry
Total Moisture	10.97%	-
Carbon	65.14%	73.17%
Hydrogen	5.65%	4.97%
Nitrogen	1.27%	1.43%
Sulfur	2.81%	3.16%
Ash	8.22%	9.23%
Oxygen	16.90%	8.04%
Chlorine		0.23%

ASH MINERAL ANALYSIS

		Dry
Silicon Dioxide	SiO_2	49.95%
Aluminum Oxide	Al_2O_3	16.51%
Ferric Oxide	Fe_2O_3	16.64%
Titanium Oxide	TiO_2	0.87%
Calcium Oxide	CaO	4.26%
Magnesium Oxide	MgO	0.84%
Sodium Oxide	Na_2O	0.85%
Potassium Oxide	K_2O	2.45%
Phosphorous Pentoxide	P_2O_5	0.26%
Sulfur Trioxide	SO_3	4.20%
Manganes Oxide	MnO	0.02%
Undetermined		3.15%

OTHER PROPERTIES

	Dry
Free Swellind Index	
Oxidation (% Transmittance)	92
Hardgrove Grindability Index	56
Base:Acid Ratio	0.37
Slagging Index	1.18
Fouling Index	0.32
Silica Value	69.67
Alkali Content	2.46
Equilibrium Moisture	6.66
T250 (F)	

Ash Fusion Tempertures

	Reducing	Oxidizing
Initial Deformation Temperature	2020°	2352°
Softening Temperature, Spherical	2116°	2395°
Softening Temperature, Hemispherical	2265°	2472°
Fluid Temperature	2322°	2544°

SULFUR FORMS

	Dry
% Pyritic Sulfur	1.17%
% Sulfate Sulfur	0.31%
% Organic Sulfur	1.68%
% Total Sulfur	3.16%

METALS

	PPM
Arsenic	2.16
Mercury	0.092

James River

Triad Mining, Inc.
Hurricane Creek Mine
No.5 Coal - Washed

	Average	Minimum	Maximum	# Samples
Proximate Analysis				
Moisture	13.00			Grid
Ash	7.70	6.24	9.35	Grid
BTU/lb	11,553	11,325	11,861	Grid
Sulfur	2.95	2.36	4.12	Grid
SO2	5.11	4.02	7.21	Grid
Volatile (%dry)	42.13	40.15	44.17	6
Fixed Carbon (%dry)	49.12	47.28	51.37	6
EQ Mois.	8.69	7.67	9.60	6
Free Swelling Index	4.3	4.0	5.0	6
Ash Fusion Temperatures (Deg. F)				
Reducing				
Initial	2,179	2,110	2,265	6
Softening	2,289	2,200	2,435	6
Hemispherical	2,353	2,250	2,460	6
Final	2,398	2,310	2,480	6
Oxidizing				
Initial	2,495	2,420	2,545	6
Softening	2,543	2,480	2,570	6
Hemispherical	2,558	2,500	2,590	6
Final	2,574	2,520	2,610	6
Hardgrove Grindability Index				
(HGI)	59.0	55.0	65.0	6
@ mols.	2.69	1.53	3.89	6
Alkalies (% Dry Basis)				
Acid Soluble				
Sodium Oxide	0.015	0.008	0.023	6
Potassium Oxide	0.002	0.001	0.002	6
Water Soluble				
Sodium Oxide	0.018	0.009	0.029	6
Potassium Oxide	0.002	0.002	0.003	6
Ultimate Analysis				
% Dry				
Carbon	73.59	72.84	74.79	6
Hydrogen	5.15	5.07	5.23	6
Nitrogen	1.43	1.35	1.50	6
Oxygen	7.77	7.28	8.63	6

	Average	Minimum	Maximum	# Samples
Mineral Analysis of Ash (% Ignited Basis)				
Silican Dioxide	50.58	47.32	53.80	6
Aluminum Oxide	21.09	20.00	23.20	6
Ferric Oxide	19.32	15.96	24.66	6
Titanium Dioxide	1.07	0.84	1.28	6
Calcium Oxide	0.91	0.56	1.68	6
Potassium Oxide	2.62	2.44	2.98	6
Magnesium Oxide	0.92	0.74	1.04	6
Sodium Oxide	0.40	0.26	0.56	6
Phosphorus Pentoxide	0.09	0.07	0.11	6
Sulfur Trioxide	0.58	0.28	1.32	6
Barium Oxide	0.04	0.03	0.06	6
Manganese Oxide	0.02	0.02	0.03	6
Strontium Oxide	0.02	0.01	0.02	6
Undetermined	2.36	1.98	2.65	6
Base/Acid Ratio	0.34	0.27	0.43	6
Slag Visc. @ T250 poise	2,498	2,370	2,605	6
Fouling Index	0.13	0.09	0.16	6
Slagging Index	1.13	0.83	1.78	6
Silica Value	70.58	64.31	75.56	6
% Alkali as Na2O	0.19	0.17	0.20	6
Silica/Alumina Ratio	2.40	2.22	2.47	6
Forms of Sulfur (% Dry Basis)				
Total	3.31	2.97	4.13	6
Pyritic	1.14	0.88	1.41	6
Sulfate	0.02	0.01	0.03	6
Organic	2.16	1.93	2.79	6
Chlorine (PPM Dry)	285.0	10.0	800.0	6
Fluorine (PPM Dry)	45.0	40.0	60.0	6
Mercury (PPM Dry)	0.09	0.07	0.11	6
Arsenic (PPM Dry)	2.9	1.6	4.0	6

HIGHLAND No.9

TYPICAL ANALYSIS
2005 through 2010

Washed Basis
Seam 9
State of Kentucky

Report Data 3/30/2006

Proximate Analysis	As Received	Dry
Moisture	12.5	
Ash	8.4	9.6
Volatile Matter	36.8	42.1
Fixed Carbon	42.3	48.3
BTU	11386	13012
Sulfur	2.98	3.40
MAFBTU	14394	
Lb. SO2/MMBTU	5.22	

Ultimate Analysis	
Carbon	72.7
Hydrogen	5.0
Nitrogen	1.5
Chlorine	0.12
Sulfur	3.40
Ash	9.6
Oxygen	7.68

Sulfur Forms	
Pyritic	1.17
Sulfate	0.02
Organic	2.21

Water Soluble Alkalies	
Sodium Oxide	0.050
Potassium Oxide	0.004

Equilibrium Moisture	9.4
Free Swelling Index	4.0
Hardgrove Grindability Index	53
Mercury Hg ppm (Dry Whole Coal Basis)	0.07

Ash Fusion	
Reducing Atmosphere	
Initial Deformation (I.D.)	2025
Softening (H=W)	2075
Hemispherical (H=1/2W)	2145
Fluid	2310
Oxidizing Atmosphere	
Initial Deformation (I.D.)	2330
Softening (H=W)	2375
Hemispherical (H=1/2W)	2435
Fluid	2520

Mineral Analysis Of Ash (Ignited Basis)	
Silica (SiO2)	48.7
Alumina (Al2O3)	18.0
Titania (TiO2)	0.9
Ferric Oxide (Fe2O3)	18.9
Lime (CaO)	5.8
Magnesia (MgO)	0.9
Potassium Oxide (K2O)	2.2
Sodium Oxide (Na2O)	0.9
Phosphorous Pentoxide (P2O5)	0.1
Sulfur Trioxide (SO3)	3.5
Strontium Oxide (SrO)	<0.1
Barium Oxide (BaO)	0.1
Manganese Dioxide (MnO2)	<0.1

Alkalies As Na2O	0.23
Base/Acid Ratio	0.42
Silica Value	65.55
Slag Viscosity @ T250	2385

All analyses are subject to revision due to additional coring, conditions specified in the coal supply agreement, actual operating conditions at time of mining, type of preparation at time of mining, or federal and state regulations. Analysis intended for informational purposes only.

Source Of Information	*Proximate analysis based on mine model done August 2005. Remainder of analysis based on core composites and Camp No.9 production data base samples.*

Prepared by W.B. Emke

MLI
MINERAL LABS, INC.

MINERAL LABS, INC.

Box 549
Salyersville, Kentucky 41465
Phone (606) 349-6145

COMPANY REQUESTING ANALYSIS:

Date Analyzed: 11/02/05

Lab No.: 951100631 4731

Sample Taken By: CUSTOMER

EAST KY POWER/GILBERT
1301 WEST 2ND ST. PO BOX 398
ATTN: JACKIE LOGAN
MAYSVILLE, KY. 41056

Sample I.D.:
CT MB MH8 SP-618 SAMPLE WT = 56.70 LBS

Middle 8
Perry County, KY

PROXIMATE ANALYSIS	As Received	Dry Basis	M.A.F. B.T.U.
% Moisture	5.53		
% Ash	10.62	11.25	
% Volatile	XXX	XXX	
% Fixed Carbon	XXX	XXX	
B.T.U.	12,364	13,088	14,746
% Sulfur	4.74	5.02	

ULTIMATE ANALYSIS	As Received	Dry Basis
Moisture	5.53	
Carbon	70.10	74.20
Hydrogen	4.79	5.07
Nitrogen	1.27	1.34
Chlorine	0.06	0.06
Sulfur	4.74	5.02
Ash	10.62	11.25
Oxygen (diff.)	2.89	3.06

- SULFUR FORMS -		
% Pyritic Sulfur	XXX	XXX
% Sulfate Sulfur	XXX	XXX
% Organic Sulfur	XXX	XXX
% Total Sulfur	XXX	XXX
T-250 Temp. of Ash	XXX	XXX

- FUSION TEMPERATURE OF ASH -	Reducing	Oxidizing
Initial	1980 °F	XXX °F
Softening	2040 °F	XXX °F
Hemispherical	2090 °F	XXX °F
Fluid	2180 °F	XXX °F

- MINERAL ANALYSIS -	% Wt. Ignited Basis
Phos. pentoxide, P_2O_5	0.24
Silica, SiO_2	27.49
Ferric oxide, Fe_2O_3	44.16
Alumina, Al_2O_3	18.96
Titania, TiO_2	0.60
Lime, CaO	1.18
Magnesia, MgO	0.51
Sulfur trioxide, SO_3	1.50
Potassium oxide, K_2O	2.63
Sodium oxide, Na_2O	0.18
Undetermined	2.55

Base/Acid Ratio XXX

% Mercury XXX

Water Soluable Alkalies

As Na_2O XXX

As K_2O XXX

- HARDGROVE GRINDABILITY INDEX 43

- FREE SWELLING INDEX XXX

- EQUILIBRIUM MOISTURE XXX

4111460

Submitted By

MLI MINERAL LABS, INC.

MINERAL LABS, INC.

Box 549
Salyersville, Kentucky 41465
Phone (606) 349-6145

COMPANY REQUESTING ANALYSIS:

Date Analyzed: 10/11/05

Lab No.: 951100575 4731

Sample Taken By: CUSTOMER

EAST KY POWER/GILBERT
1301 WEST 2ND ST. PO BOX 398
ATTN: JACKIE LOGAN
MAYSVILLE, KY. 41056

Sample I.D.:
HARLENE TIPPLE K-6 Hazard 8 split 2 Perry County, KY

PROXIMATE ANALYSIS	As Received	Dry Basis	M.A.F. B.T.U.
% Moisture	4.79		
% Ash	10.80	11.34	
% Volatile	XXX	XXX	
% Fixed Carbon	XXX	XXX	
B.T.U.	12,626	13,282	14,980
% Sulfur	3.24	3.40	

ULTIMATE ANALYSIS	As Received	Dry Basis
Moisture	4.79	
Carbon	72.60	76.25
Hydrogen	4.73	4.97
Nitrogen	1.32	1.39
Chlorine	0.14	0.15
Sulfur	3.24	3.40
Ash	10.80	11.34
Oxygen (diff.)	2.38	2.50

- SULFUR FORMS -		
% Pyritic Sulfur	XXX	XXX
% Sulfate Sulfur	XXX	XXX
% Organic Sulfur	XXX	XXX
% Total Sulfur	XXX	XXX
T-250 Temp. of Ash	XXX	XXX

- FUSION TEMPERATURE OF ASH -	Reducing	Oxidizing
Initial	2000 °F	XXX °F
Softening	2050 °F	XXX °F
Hemispherical	2140 °F	XXX °F
Fluid	2350 °F	XXX °F

- MINERAL ANALYSIS -	% Wt. Ignited Basis
Phos. pentoxide, P_2O_5	0.69
Silica, SiO_2	37.94
Ferric oxide, Fe_2O_3	30.18
Alumina, Al_2O_3	19.77
Titania, TiO_2	0.80
Lime, CaO	1.93
Magnesia, MgO	1.07
Sulfur trioxide, SO_3	1.40
Potassium oxide, K_2O	3.37
Sodium oxide, Na_2O	0.27
Undetermined	2.58

Base/Acid Ratio XXX

% Mercury XXX

Water Soluable Alkalies

As Na_2O XXX

As K_2O XXX

- HARDGROVE GRINDABILITY INDEX XXX

- FREE SWELLING INDEX XXX

- EQUILIBRIUM MOISTURE XXX

3110210

Submitted By Kenny Bailey

MLI MINERAL LABS, INC.

MINERAL LABS, INC.

Box 549
Salyersville, Kentucky 41465
Phone (606) 349-6145

COMPANY REQUESTING ANALYSIS:

Date Analyzed: 8/16/06

Lab No.: 860800489 4848

Sample Taken By: LAB

TRINITY/LITTLE ELK MINING
1051 MAIN STREET SUITE 100
ATTN: TIM KLAIBER
MILTON, WV 25541

Sample I.D.:
BIG ELK AUGER 9 WASH
FOULING FACTOR = 0.0680
SLAGGING FACTOR = 0.8165

PROXIMATE ANALYSIS	As Received	Dry Basis	M.A.F. B.T.U.
% Moisture	4.72		
% Ash	13.20	13.86	
% Volatile	36.88	38.71	
% Fixed Carbon	45.20	47.43	
B.T.U.	12,188	12,793	14,850
% Sulfur	2.98	3.12	

ULTIMATE ANALYSIS	As Received	Dry Basis
Moisture	4.72	
Carbon	69.34	72.78
Hydrogen	4.53	4.75
Nitrogen	1.38	1.45
Chlorine	0.05	0.05
Sulfur	2.98	3.12
Ash	13.20	13.86
Oxygen (diff.)	3.80	3.99

- SULFUR FORMS -		
% Pyritic Sulfur	1.30	1.36
% Sulfate Sulfur	0.05	0.05
% Organic Sulfur	1.63	1.71
% Total Sulfur	2.98	3.12
T-250 Temp. of Ash	XXX	XXX

- FUSION TEMPERATURE OF ASH -	Reducing	Oxidizing
Initial	2300 °F	XXX °F
Softening	2420 °F	XXX °F
Hemispherical	2500 °F	XXX °F
Fluid	2560 °F	XXX °F

- MINERAL ANALYSIS -	% Wt. Ignited Basis
Phos. pentoxide, P_2O_5	0.22
Silica, SiO_2	50.01
Ferric oxide, Fe_2O_3	16.32
Alumina, Al_2O_3	25.24
Titania, TiO_2	1.17
Lime, CaO	1.04
Magnesia, MgO	1.00
Sulfur trioxide, SO_3	0.83
Potassium oxide, K_2O	1.38
Sodium oxide, Na_2O	0.26
Undetermined	2.53

Base/Acid Ratio 0.2617

% Mercury XXX

Water Soluble Alkalies

As Na_2O 0.02

As K_2O 0.05

- HARDGROVE GRINDABILITY INDEX 42
- FREE SWELLING INDEX 4
- EQUILIBRIUM MOISTURE 3.1%

5080368

Submitted By R. Jones

MLI MINERAL LABS, INC.

Box 549, Salyersville, Kentucky 41465
(606) 349-6145 • Fax (606) 349-6106

August 18, 2006
LAB # 860800489

TRINITY/LITTLE ELK MINING
1051 MAIN STREET SUITE 100
ATTN: TIM KLAIBER
MILTON, WV 25541

SAMPLE ID: BIG ELK AUGER 9 WASH

BASIC TRACE ELEMENT ANALYSIS (ppm)
AS REC'D COAL BASIS

Beryllium	3.67
Cadmium	0.14
Chromium	11.66
Copper	15.74
Lead	9.28
Manganese	23.10
Nickel	11.83
Vanadium	33.89
Zinc	13.56

ADDITIONAL METALS (ppm)
AS REC'D COAL BASIS

Antimony	0.58
Arsenic	9.18
Barium	105.9
Boron	11.96
Bromine	8.04
Chlorine	500.00
Cobalt	6.24
Fluorine	38.6
Lithium	36.24
Mercury	0.1
Molybdenum	0.15
Selenium	1.67
Silver	0.02
Strontium	27.79
Thallium	0.96
Tin	1.89
Zirconium	29.33

*ALL TRACE ELEMENTS ARE ppm AS REC'D COAL BASIS

Submitted By [signature]

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
COOPER STATION
ARMSTRONG
S-667
SCRUBBER 595
6/16/08

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 16, 2008

Date received: June 23, 2008

Analysis Report No. 49-355336

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.41	xxxxx
% Ash	9.81	10.26
% Volatile	37.65	39.39
% Fixed Carbon	48.13	50.35
	100.00	100.00
Btu/lb	12665	13249
% Sulfur	2.00	2.09
MAF Btu		14764
Alk. as Sodium Oxide	0.17	0.18

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.41	xxxxx
% Carbon	70.50	73.75
% Hydrogen	4.82	5.04
% Nitrogen	1.26	1.32
% Sulfur	2.00	2.09
% Ash	9.81	10.26
% Oxygen(diff)	7.20	7.54
	100.00	100.00

FUSION TEMPERATURE OF ASH, (ºF)

	Reducing	Oxidizing
Initial Deformation (IT)	2695	xxxx
Softening (ST)	2700+	xxxx
Hemispherical (HT)	2700+	xxxx
Fluid (FT)	2700+	xxxx

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
COOPER STATION
ARMSTRONG
S-667
SCRUBBER 595
6/16/08

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 16, 2008

Date received: June 23, 2008

Analysis Report No. 49-355336

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	50.50
Aluminum oxide	28.80
Titanium dioxide	1.28
Iron oxide	14.00
Calcium oxide	1.34
Magnesium oxide	0.72
Potassium oxide	2.33
Sodium oxide	0.24
Sulfur trioxide	0.10
Phosphorus pentoxide	0.22
Strontium oxide	0.11
Barium oxide	0.08
Manganese oxide	0.02
Undetermined	0.26
	100.00

Silica Value = 75.87
Base:Acid Ratio = 0.23
T_{250} Temperature = 2690 ^{o}F

Type of Ash = BITUMINOUS
Fouling Index = 0.06
Slagging Index = 0.48

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS North America Inc. | Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

F 465

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
COOPER STATION
ARMSTRONG
S-667
SCRUBBER 595
6/16/08

Kind of sample reported to us	COAL
Sample taken at	EAST KENTUCKY POWER CO-OP
Sample taken by	EAST KENTUCKY POWER CO-OP
Date sampled	June 16, 2008
Date received	June 23, 2008

Analysis Report No. 49-355336

Mercury	0.19 ppm	06-26-2008 03:13 MLB
Chloride	0.04 %	06-28-2008 05:25 MLB

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
COOPER STATION
ARMSTRONG
S-671
SCRUBBER 595
6/16/08

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 16, 2008

Date received: June 23, 2008

Analysis Report No. 49-355335

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.17	xxxxx
% Ash	11.28	11.90
% Volatile	35.67	37.61
% Fixed Carbon	47.88	50.49
	100.00	100.00
Btu/lb	12332	13004
% Sulfur	1.54	1.62
MAF Btu		14760
Alk. as Sodium Oxide	0.34	0.36

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.17	xxxxx
% Carbon	68.88	72.64
% Hydrogen	4.66	4.91
% Nitrogen	1.41	1.49
% Sulfur	1.54	1.62
% Ash	11.28	11.90
% Oxygen(diff)	7.06	7.44
	100.00	100.00

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2275	xxxx
Softening (ST)	2310	xxxx
Hemispherical (HT)	2540	xxxx
Fluid (FT)	2585	xxxx

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
COOPER STATION
ARMSTRONG
S-671
SCRUBBER 595
6/16/08

Kind of sample reported to us	COAL
Sample taken at	EAST KENTUCKY POWER CO-OP
Sample taken by	EAST KENTUCKY POWER CO-OP
Date sampled	June 16, 2008
Date received	June 23, 2008

Analysis Report No. 49-355335

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	47.80
Aluminum oxide	26.00
Titanium dioxide	1.04
Iron oxide	16.00
Calcium oxide	2.15
Magnesium oxide	1.28
Potassium oxide	4.14
Sodium oxide	0.31
Sulfur trioxide	0.56
Phosphorus pentoxide	0.20
Strontium oxide	0.09
Barium oxide	0.16
Manganese oxide	0.08
Undetermined	0.19
	100.00

Silica Value =	71.10	Type of Ash =	BITUMINOUS
Base:Acid Ratio =	0.32	Fouling Index =	0.10
T_{250} Temperature =	2520 °F	Slagging Index =	0.52

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
COOPER STATION
ARMSTRONG
S-671
SCRUBBER 595
6/16/08

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 16, 2008

Date received: June 23, 2008

Analysis Report No. 49-355335

Mercury	0.13 ppm	06-26-2008 03:13	MLB
Chloride	0.12 %	06-28-2008 05:10	MLB

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
S-673
SCRUBBER

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 17, 2008

Date received June 23, 2008

Analysis Report No. 49-355334

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	3.09	xxxxx
% Ash	8.00	8.25
% Volatile	38.14	39.36
% Fixed Carbon	50.77	52.39
	100.00	100.00
Btu/lb	13369	13795
% Sulfur	3.01	3.11
MAF Btu		15035
Alk. as Sodium Oxide	0.17	0.18

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	3.09	xxxxx
% Carbon	73.72	76.07
% Hydrogen	4.86	5.01
% Nitrogen	1.54	1.59
% Sulfur	3.01	3.11
% Ash	8.00	8.25
% Oxygen(diff)	5.78	5.97
	100.00	100.00

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2058	xxxx
Softening (ST)	2080	xxxx
Hemispherical (HT)	2170	xxxx
Fluid (FT)	2239	xxxx

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
S-673
SCRUBBER

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 17, 2008

Date received: June 23, 2008

Analysis Report No. 49-355334

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	38.50
Aluminum oxide	20.40
Titanium dioxide	0.87
Iron oxide	33.30
Calcium oxide	1.91
Magnesium oxide	0.90
Potassium oxide	2.80
Sodium oxide	0.31
Sulfur trioxide	0.22
Phosphorus pentoxide	0.21
Strontium oxide	0.06
Barium oxide	0.09
Manganese oxide	0.03
Undetermined	0.40
	100.00

Silica Value = 51.60
Base:Acid Ratio = 0.66
T_{250} Temperature = 2220 ^{o}F

Type of Ash = BITUMINOUS
Fouling Index = 0.20
Slagging Index = 2.05

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS North America Inc. | Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals
Member of the SGS Group

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
S-673
SCRUBBER

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 17, 2008

Date received: June 23, 2008

Analysis Report No. 49-355334

Mercury	0.33 ppm	06-26-2008 03:13	MLB
Chloride	0.01 %	06-28-2008 04:45	MLB

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

Cooper Scrubber

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
S-674-1
SCRUBBER
595
GATLIFF

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 17, 2008

Date received: June 23, 2008

Analysis Report No. 49-355333

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	4.13	xxxxx
% Ash	14.31	14.93
% Volatile	37.94	39.57
% Fixed Carbon	43.62	45.50
	100.00	100.00
Btu/lb	11910	12423
% Sulfur	2.92	3.05
MAF Btu		14603
Alk. as Sodium Oxide	0.26	0.27

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	4.13	xxxxx
% Carbon	66.39	69.25
% Hydrogen	4.47	4.66
% Nitrogen	1.14	1.19
% Sulfur	2.92	3.05
% Ash	14.31	14.93
% Oxygen(diff)	6.64	6.92
	100.00	100.00

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2590	xxxx
Softening (ST)	2630	xxxx
Hemispherical (HT)	2700+	xxxx
Fluid (FT)	2700+	xxxx

Respectfully submitted,
SGS NORTH AMERICA INC

Middlesboro Laboratory

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
S-674-1
SCRUBBER
595

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 17, 2008

Date received: June 23, 2008

Analysis Report No. 49-355333

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	52.50
Aluminum oxide	27.30
Titanium dioxide	1.86
Iron oxide	12.90
Calcium oxide	1.09
Magnesium oxide	0.78
Potassium oxide	2.43
Sodium oxide	0.21
Sulfur trioxide	0.11
Phosphorus pentoxide	0.14
Strontium oxide	0.06
Barium oxide	0.15
Manganese oxide	0.02
Undetermined	0.45
	100.00

Silica Value = 78.04
Base:Acid Ratio = 0.21
T_{250} Temperature = 2730 ^{o}F

Type of Ash = BITUMINOUS
Fouling Index = 0.04
Slagging Index = 0.64

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

July 2, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
S-674-1
SCRUBBER
595

Kind of sample reported to us: COAL

Sample taken at: EAST KENTUCKY POWER CO-OP

Sample taken by: EAST KENTUCKY POWER CO-OP

Date sampled: June 17, 2008

Date received: June 23, 2008

Analysis Report No. 49-355333

Mercury	0.27 ppm	06-26-2008 03:13	MLB
Chloride	0.03 %	06-28-2008 04:35	MLB

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

August 18, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
DALE GATLIFF
2116

Kind of sample reported to us	COAL
Sample taken at	EAST KENTUCKY POWER CO-OP
Sample taken by	EAST KENTUCKY POWER CO-OP
Date sampled	August 2, 2008
Date received	August 5, 2008

Analysis Report No. 49-358388

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.45	xxxxx
% Ash	7.43	7.94
% Volatile	35.00	37.41
% Fixed Carbon	51.12	54.65
	100.00	100.00
Btu/lb	12882	13770
% Sulfur	0.88	0.94
MAF Btu		14958
Alk. as Sodium Oxide	0.16	0.17

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.45	xxxxx
% Carbon	72.06	77.03
% Hydrogen	4.70	5.02
% Nitrogen	1.40	1.50
% Sulfur	0.88	0.94
% Ash	7.43	7.94
% Oxygen(diff)	7.08	7.57
	100.00	100.00

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2700+	xxxx
Softening (ST)	2700+	xxxx
Hemispherical (HT)	2700+	xxxx
Fluid (FT)	2700+	xxxx

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

August 18, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
DALE GATLIFF
2116

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled August 2, 2008

Date received August 5, 2008

Analysis Report No. 49-358388

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	52.90
Aluminum oxide	29.00
Titanium dioxide	1.48
Iron oxide	7.61
Calcium oxide	2.98
Magnesium oxide	1.32
Potassium oxide	2.31
Sodium oxide	0.61
Sulfur trioxide	0.45
Phosphorus pentoxide	0.65
Strontium oxide	0.32
Barium oxide	0.14
Manganese oxide	0.03
Undetermined	0.20
	100.00

Silica Value = 81.62
Base:Acid Ratio = 0.18
T_{250} Temperature = 2780 °F

Type of Ash = BITUMINOUS
Fouling Index = 0.11
Slagging Index = 0.17

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

August 18, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
DALE GATLIFF
2116

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled August 2, 2008

Date received August 5, 2008

Analysis report no. 49-358388

PARAMETER	RESULTS	UNITS	METHOD	DATE/TIME/ANALYST
Mercury, Hg	0.05	ppm	D6722	08/06/08 06:43 MLB
Chlorine, Cl	0.19	%	D4208	08/06/08 05:30 MLB

Procedure: Chlorine was determined by Selective Ion Method; ASTM, D 4208.
Mercury was determined by Direct Combustion Method; ASTM, D 6722.

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS North America Inc. | Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

SGS

August 18, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
DALE TRINITY
2117

Kind of sample reported to us	COAL
Sample taken at	EAST KENTUCKY POWER CO-OP
Sample taken by	EAST KENTUCKY POWER CO-OP
Date sampled	August 1, 2008
Date received	August 5, 2008

Analysis Report No. 49-358389

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.18	xxxxx
% Ash	9.34	9.96
% Volatile	34.53	36.80
% Fixed Carbon	49.95	53.24
	100.00	100.00
Btu/lb	12517	13341
% Sulfur	1.04	1.11
MAF Btu		14817
Alk. as Sodium Oxide	0.14	0.15

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.18	xxxxx
% Carbon	70.26	74.89
% Hydrogen	4.69	5.00
% Nitrogen	1.28	1.36
% Sulfur	1.04	1.11
% Ash	9.34	9.96
% Oxygen(diff)	7.21	7.68
	100.00	100.00

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2619	xxxx
Softening (ST)	2658	xxxx
Hemispherical (HT)	2700+	xxxx
Fluid (FT)	2700+	xxxx

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS North America Inc. | Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

Member of the SGS Group

F-465

SGS

August 18, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
DALE TRINITY
2117

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled August 1, 2008

Date received August 5, 2008

Analysis Report No. 49-358389

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	56.70
Aluminum oxide	28.70
Titanium dioxide	1.44
Iron oxide	7.43
Calcium oxide	1.40
Magnesium oxide	0.79
Potassium oxide	1.87
Sodium oxide	0.31
Sulfur trioxide	0.10
Phosphorus pentoxide	0.37
Strontium oxide	0.17
Barium oxide	0.13
Manganese oxide	0.02
Undetermined	0.57
	100.00

Silica Value = 85.49
Base:Acid Ratio = 0.14
T_{250} Temperature = 2880 ^{o}F

Type of Ash = BITUMINOUS
Fouling Index = 0.04
Slagging Index = 0.16

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

SGS

August 18, 2008

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE PICKED UP
DALE TRINITY
2117

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled August 1, 2008

Date received August 5, 2008

Analysis report no. 49-358389

PARAMETER	RESULTS	UNITS	METHOD	DATE/TIME/ANALYST
Mercury, Hg	0.09	ppm	D6722	08/06/08 06:30 MLB
Chlorine, Cl	0.09	%	D4208	08/08/08 06:10 MLB

Procedure: Chlorine was determined by Selective Ion Method; ASTM, D 4208.
Mercury was determined by Direct Combustion Method; ASTM, D 6722.

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 1919 SOUTH HIGHLAND AVE., SUITE 210-B, LOMBARD, ILLINOIS 60148 • TEL: 630-953-9300 FAX: 630-953-9306
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CHARLEROI, PA 15022
TEL: (724) 483-3549
FAX: (724) 483-0892
www.comteco.com

April 11, 2002

OXFORD MINING
P.O. BOX 427
COSHOCTON OH 43812
BILL SPIKER

Sample identification by
OXFORD MINING

DARON #8 HEAD SAMPLE

Kind of sample reported to us	COAL
Sample taken at	CADIZ OHIO
Sample taken by	C.T.E.
Date sampled	March 18, 2002
Date received	March 19, 2002

Analysis Report No. 43-95802

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.69	xxxxx
% Ash	11.59	12.16
% Volatile	38.69	40.59
% Fixed Carbon	45.03	47.25
	100.00	100.00
Btu/lb	12325	12931
% Sulfur	4.31	4.52
MAF Btu		14721
SO_2 lb/mill Btu @ 100%	6.99	
Alk. as Sodium Oxide	0.17	0.18

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.69	xxxxx
% Carbon	67.18	70.49
% Hydrogen	4.57	4.79
% Nitrogen	1.27	1.33
% Sulfur	4.31	4.52
% Ash	11.59	12.16
% Oxygen(diff)	6.39	6.71
	100.00	100.00
% Chlorine	0.06	0.06

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	2.34	2.46
% Sulfate	0.01	0.01
% Organic(diff)	1.96	2.05

WATER SOLUBLE ALK.

	As Received	Dry Basis
% Sodium oxide	xxxxxx	xxxxxx
% Potassium oxide	xxxxxx	xxxxxx

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2151	xxxx
Softening (ST)	2226	xxxx
Hemispherical (HT)	2290	xxxx
Fluid (FT)	2372	xxxx

GRINDABILITY INDEX = 56 at 1.99 % Moisture

NQA ISO9002 REGISTERED COMPANY
Certificate No. 7061/9

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Charleroi Laboratory

MEMBER ACIL

F-465

TERMS AND CONDITIONS ON REVERSE

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April 11, 2002

OXFORD MINING
P.O. BOX 427
COSHOCTON OH 43812
BILL SPIKER

Sample identification by
OXFORD MINING

DARON #8 HEAD SAMPLE

Kind of sample reported to us COAL

Sample taken at CADIZ OHIO

Sample taken by C.T.E.

Date sampled March 18, 2002

Date received March 19, 2002

Analysis Report No. 43-95802

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	44.13
Aluminum oxide	17.78
Titanium dioxide	0.85
Iron oxide	27.98
Calcium oxide	2.76
Magnesium oxide	0.80
Potassium oxide	1.65
Sodium oxide	0.40
Sulfur trioxide	2.07
Phosphorus pentoxide	0.27
Strontium oxide	0.04
Barium oxide	0.03
Manganese oxide	0.02
Undetermined	1.22
	100.00

Silica Value = 58.32
Base:Acid Ratio = 0.54
T_{250} Temperature = 2320 ^{o}F

Type of Ash = BITUMINOUS
Fouling Index = 0.22
Slagging Index = 2.44

ISO9002 REGISTERED COMPANY
Certificate No. 7061/9

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

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April 11, 2002

OXFORD MINING
P.O. BOX 427
COSHOCTON OH 43812
BILL SPIKER

Sample identification by
OXFORD MINING

DARON #8 HEAD SAMPLE

Kind of sample reported to us	COAL
Sample taken at	CADIZ OHIO
Sample taken by	C.T.E.
Date sampled	March 18, 2002
Date received	March 19, 2002

Analysis Report No. 43-95802

TRACE ELEMENTS IN COAL

Antimony	1.1 ppm
Arsenic	1.3 ppm
Barium	8.2 ppm
Beryllium	0.3 ppm
Cadmium	0.8 ppm
Chromium	2.6 ppm
Cobalt	0.9 ppm
Copper	1.4 ppm
Gold	<0.2 ppm
Lead	5.0 ppm
Manganese	5.5 ppm
Mercury	0.1 ppm
Molybdenum	<1.0 ppm
Nickel	1.6 ppm
Selenium	<1.0 ppm
Silver	<0.2 ppm
Strontium	10.7 ppm
Tin	<1.0 ppm
Vanadium	5.0 ppm
Zinc	4.5 ppm
Zirconium	<1.0 ppm

MQR ISO9002 REGISTERED COMPANY
Certificate No. 7061/9

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

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April 11, 2002

OXFORD MINING
P.O. BOX 427
COSHOCTON OH 43812
BILL SPIKER

Sample identification by
OXFORD MINING

DARON #8 HEAD SAMPLE

Kind of sample reported to us COAL

Sample taken at CADIZ OHIO

Sample taken by C.T.E.

Date sampled March 18, 2002

Date received March 19, 2002

Analysis Report No. 43-95802

FLUORINE 41 ug/g

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Charleroi Laboratory

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April 12, 2002

OXFORD MINING
P.O. BOX 427
COSHOCTON OH 43812
BILL SPIKER

Sample identification by
OXFORD MINING

DARON #9 HEAD SAMPLE

Kind of sample reported to us	COAL
Sample taken at	CADIZ OHIO
Sample taken by	C.T.E.
Date sampled	March 18, 2002
Date received	March 19, 2002

Analysis Report No. 43-96200

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.21	xxxxx
% Ash	14.75	15.40
% Volatile	36.74	38.35
% Fixed Carbon	44.30	46.25
	100.00	100.00
Btu/lb	11787	12305
% Sulfur	3.80	3.97
MAF Btu		14545
SO_2 lb/mill Btu @ 100%	6.45	
Alk. as Sodium Oxide	0.21	0.22

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.21	xxxxx
% Carbon	64.50	67.33
% Hydrogen	4.57	4.77
% Nitrogen	1.25	1.31
% Sulfur	3.80	3.97
% Ash	14.75	15.40
% Oxygen(diff)	6.92	7.22
	100.00	100.00
% Chlorine	0.07	0.07

FORMS OF SULFUR

	As Received	Dry Basis
% Pyritic	1.72	1.80
% Sulfate	0.02	0.02
% Organic(diff)	2.06	2.15

WATER SOLUBLE ALK.

	As Received	Dry Basis
% Sodium oxide	xxxxxx	xxxxxx
% Potassium oxide	xxxxxx	xxxxxx

FUSION TEMPERATURE OF ASH, (°F)

	Reducing	Oxidizing
Initial Deformation (IT)	2094	xxxx
Softening (ST)	2203	xxxx
Hemispherical (HT)	2245	xxxx
Fluid (FT)	2340	xxxx

GRINDABILITY INDEX = 53

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Charleroi Laboratory

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April 12, 2002

OXFORD MINING
P.O. BOX 427
COSHOCTON OH 43812
BILL SPIKER

Sample identification by
OXFORD MINING

DARON #9 HEAD SAMPLE

Kind of sample reported to us COAL

Sample taken at CADIZ OHIO

Sample taken by C.T.E.

Date sampled March 18, 2002

Date received March 19, 2002

Analysis Report No. 43-96200

ANALYSIS OF ASH	**WEIGHT %, IGNITED BASIS**
Silicon dioxide	46.11
Aluminum oxide	18.80
Titanium dioxide	0.80
Iron oxide	25.55
Calcium oxide	2.92
Magnesium oxide	0.78
Potassium oxide	1.49
Sodium oxide	0.42
Sulfur trioxide	2.22
Phosphorus pentoxide	0.25
Strontium oxide	0.09
Barium oxide	0.05
Manganese oxide	0.04
Undetermined	0.48
	100.00

Silica Value = 61.19
Base:Acid Ratio = 0.47
T_{250} **Temperature** = 2365 °F

Type of Ash = BITUMINOUS
Fouling Index = 0.20
Slagging Index = 1.87

MQA ISO9002 REGISTERED COMPANY
Certificate No. 7061/9

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Charleroi Laboratory

MEMBER ACIL

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TERMS AND CONDITIONS ON REVERSE

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April 12, 2002

OXFORD MINING
P.O. BOX 427
COSHOCTON OH 43812
BILL SPIKER

Sample identification by
OXFORD MINING

DARON #9 HEAD SAMPLE

Kind of sample reported to us	COAL
Sample taken at	CADIZ OHIO
Sample taken by	C.T.E.
Date sampled	March 18, 2002
Date received	March 19, 2002

Analysis Report No. 43-96200

TRACE ELEMENTS IN COAL

Antimony	1.3 ppm
Arsenic	2.0 ppm
Barium	11.2 ppm
Beryllium	0.6 ppm
Cadmium	0.6 ppm
Chromium	3.8 ppm
Cobalt	1.1 ppm
Copper	1.7 ppm
Gold	<0.2 ppm
Lead	3.9 ppm
Manganese	6.9 ppm
Mercury	0.1 ppm
Molybdenum	<1.0 ppm
Nickel	0.8 ppm
Selenium	<1.0 ppm
Silver	<0.2 ppm
Strontium	12.9 ppm
Tin	<1.0 ppm
Vanadium	6.6 ppm
Zinc	6.0 ppm
Zirconium	<1.0 ppm

NQA ISO9002 REGISTERED COMPANY
Certificate No. 7061/9

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Charleroi Laboratory

MEMBER ACIL

F-465

East Kentucky Power Cooperative
Cooper Station

Armstrong Wood Analysis

Date	%Moisture	% Ash	% Sulfur	Btu	Btu dry	MAF
Avg.	6.87	0.44	0.02	7525	8080	8118
STDEV.	2.52	0.11	0.01	236	129	130
Total	247.45	15.78	0.66	270887	290883	292265
07/17/07	4.75	0.74	0.03	7693	8077	8140
08/02/07	8.29	0.46	0.03	7329	7992	8032
08/11/07	6.95	0.39	0.03	7424	7979	8013
08/13/07	6.19	0.49	0.01	7563	8062	8104
08/20/07	5.68	0.36	0.02	7460	7910	7940
08/31/07	6.60	0.60	0.03	7667	8209	8263
09/11/07	18.93	0.48	0.00	6638	8188	8237
09/18/07	6.04	0.45	0.02	7476	7957	7995
09/24/07	6.16	0.56	0.01	7712	8218	8267
10/01/07	5.04	0.41	0.01	7640	8045	8080
10/10/07	13.40	0.77	0.02	6775	7824	7894
10/15/07	6.19	0.42	0.02	7787	8301	8339
10/23/07	7.72	0.31	0.02	7373	7990	8017
10/29/07	5.73	0.37	0.02	7667	8133	8165
11/06/07	5.87	0.39	0.02	7577	8050	8083
11/20/07	6.60	0.40	0.02	7666	8208	8243
11/26/07	8.98	0.54	0.02	7621	8373	8424
12/03/07	6.44	0.35	0.02	7554	8074	8105
12/10/07	6.89	0.42	0.02	7427	7976	8012
12/17/07	7.69	0.34	0.02	7429	8048	8078
01/02/08	6.24	0.41	0.02	7659	8168	8204
01/07/08	5.75	0.53	0.01	7640	8106	8152
01/14/08	6.60	0.52	0.02	7401	7924	7969
01/21/08	5.24	0.37	0.02	7831	8264	8296
01/28/08	5.99	0.58	0.02	7404	7876	7925
02/04/08	6.79	0.43	0.01	7644	8201	8239
02/11/08	5.39	0.24	0.02	7684	8121	8142
02/18/08	6.73	0.33	0.01	7634	8185	8215
02/25/08	6.39	0.44	0.01	7652	8174	8213
03/03/08	6.03	0.51	0.02	7698	8191	8236
04/01/08	6.28	0.34	0.02	7602	8111	8140
04/07/08	6.03	0.42	0.02	7586	8073	8109
04/14/08	6.08	0.32	0.01	7452	7934	7961
04/29/08	5.73	0.34	0.02	7608	8071	8100

East Kentucky Power Cooperative
Cooper Station

Armstrong Wood Analysis

05/04/08	5.70	0.38	0.02	7410	7858	7890
05/12/08	6.34	0.37	0.02	7504	8012	8043

PPL Sample No.	8-2384-F
Sample I.D.	KY Switchgrass
Sample Date	
Fuel Properties - As Received	
% Total Moisture	5.04
% Volatile Matter	76.47
% Fixed Carbon	15.96
% Ash	2.53
HHV Btu/lb	7764
% Moisture	5.04
% Hydrogen	5.56
% Carbon	46.38
% Sulfur	0.05
% Nitrogen	0.24
% Oxygen (diff)	40.20
% Chlorine	0.047
% Ash	2.53
% Total	100.05
lbs Ash/MM Btu	3.26
lbs SO2/MM Btu	0.13
LHV Q_p(net) Btu/lb	7197
HHV (MAF basis)	8400
lbs Air(wet)/MMBtu	722
lbs H2O/MM Btu	70.9
Fuel Properties - Dry Basis	
% Volatile Matter	80.53
% Fixed Carbon	16.81
% Ash	2.66
HHV Btu/lb	8176
% Hydrogen	5.86
% Carbon	48.84
% Sulfur	0.05
% Nitrogen	0.25
% Oxygen (diff)	42.33
% Chlorine	0.049
% Ash	2.66
% Total	100.05
% Fluorine	0.000

Coal Ash Properties

ALSTOM Power Inc.
2000 Day Hill Road
Windsor, CT 06095
Tel: (860) 285-2464
Fax: (860) 285-5129