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August 21, 2013

VIA HAND DELIVERY

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
P.O. Box 615
Frankfort, Kentucky 40602

RE: *In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for Alteration of Certain Equipment at the Cooper Station and Approval of a Compliance Plan Amendment for Environmental Surcharge Cost Recovery*, Case No. 2013-00259

Dear Mr. Derouen:

Enclosed for filing, please find one original and ten copies of the Application of East Kentucky Power Cooperative, Inc. ("EKPC") for approval of an Amended Environmental Surcharge Compliance Plan ("Amended Plan"); a Revised Environmental Surcharge to Recover the Costs of the Amended Plan; and for issuance of a Certificate of Public Convenience and Necessity for the Cooper 1 Duct Reroute Project (the "Application"). In addition, EKPC is filing an original and ten copies of a Motion for Confidential Treatment of certain exhibits attached to the aforementioned Application. Please return file-stamped copies of these filings to my office.

If you have any questions or require additional information, please contact me.

Very truly yours,

Mark David Goss

Mark David Goss

Enc.

cc: Hon. Jennifer B. Hans
Hon. Michael L. Kurtz

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

RECEIVED

AUG 21 2013

PUBLIC SERVICE
COMMISSION

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	))))))))	PSC CASE NO. 2013-00259

APPLICATION

Comes now East Kentucky Power Cooperative, Inc. ("Applicant" or "EKPC"), by and through counsel, pursuant to KRS 278.020(1), KRS 278.183, 807 KAR 5:001, Sections 14 and 15, and other applicable law, and for its Application requesting that the Kentucky Public Service Commission ("Commission") enter an Order authorizing and approving Applicant's Certificate of Public Convenience and Necessity ("CPCN") for the rerouting of certain duct work at the Cooper Station, and approving an environmental compliance plan amendment for purposes of recovering the costs of this alteration through EKPC's environmental surcharge, respectfully pleads as follows:

I. INTRODUCTION

1. EKPC's 2012 Integrated Resource Plan, filed with the Commission as Case No. 2012-00149, indicated a future need to acquire up to 300 MW of capacity in light of anticipated idling or retirement of existing generation capacity that will result from the implementation and

enforcement of new environmental regulations. EKPC conducted a Request For Proposal ("RFP") process in 2012 to identify the best resource, or mix of resources, to satisfy the anticipated capacity requirements.

2. The RFP identified a clear, least-cost option for filling a significant portion of the anticipated capacity need. That option involves re-routing the existing duct work for EKPC's Cooper Station Unit #1 ("Cooper #1") such that its emissions are able to flow to the Cooper Station Unit #2 Air Quality Control System ("Cooper #2 AQCS"). For a capital investment of approximately $15 million, EKPC will be able to retain 116 MW of existing capacity, thereby reducing its needs to procure new capacity from other sources. This option, which shall be referred to herein as the "Project," is significantly cheaper than other capacity options available to EKPC.

3. For the reasons set forth herein below, EKPC respectfully requests that: (1) the Commission issue a Certificate of Public Convenience and Necessity ("CPCN"), pursuant to KRS 278.020(1) for the Project; and (2) it be allowed to amend its Environmental Surcharge Compliance Plan, pursuant to KRS 278.183, and permit EKPC to recover the costs associated with the amended Environmental Compliance Plan through its existing environmental surcharge mechanism.

4. Pursuant to 807 KAR 5:001, Section 14(1), EKPC's mailing address is P.O. Box 707, Winchester, Kentucky 40392-0707 and its electronic mail address is psc@ekpc.coop.

5. Pursuant to 807 KAR 5:001, Section 14(3), a certified copy of EKPC's restated Articles of Incorporation and all amendments thereto have previously been filed of record in Case No. 90-197.

II. BACKGROUND

6. The Cooper Station was originally constructed in 1962 and consists of two electric generating units. Cooper #1 began commercial operations in 1965 and is rated at 116 MW of capacity. Cooper #2 began commercial operations in 1969 and is rated at 225 MW of capacity.

7. As part of a 2007 Consent Decree with the United States Environmental Protection Agency ("EPA"), EKPC agreed to construct a scrubber and other environmental equipment to service Cooper #2. The Commission granted a CPCN to EKPC for the construction of the Cooper #2 AQCS on May 1, 2009 in Case No. 2008-00472. The Cooper #2 AQCS became operational in 2012.

8. Since entering into the Consent Decree, the EPA has continued to impose more rigid regulations upon electric generation units, including those owned by EKPC. These regulations include: the Mercury and Air Toxics Standard ("MATS"), Best Available Retrofit Technology ("BART") and the Regional Haze State Implementation Plan ("SIP").

9. EPA published the final MATS rule in the Federal Register on February 16, 2012. MATS require new and existing coal and oil-fired electric generating units ("EGUs") to meet emission limits for three categories of pollutants: mercury, acid gases and non-mercury hazardous air pollutant ("HAP") metals. MATS allow EGUs to comply with a filterable Particulate Matter emission limit as a surrogate for all non-mercury HAP metals. In addition, MATS allow coal-fired EGUs equipped with a wet or dry flue-gas desulfurization or dry sorbent injection system and a sulfur dioxide ("SO_2") continuous emission monitoring systems ("CEMs") to comply with a SO_2 emission limit instead of a hydrogen chloride acid gas emissions limit. MATS allow existing sources to comply with these emission limits through quarterly stack testing or using CEMs.

10. The 1977 amendments to the Clean Air Act ("CAA") created a program for protecting visibility of Class I areas, such as national parks. In 1990, Congress added Section 169B to the CAA to address regional haze issues. The EPA promulgated regulations in 1999 to address regional haze, which required Kentucky and other states to prepare Regional Haze SIPs. The states were also required under the CAA to evaluate the use of retrofit controls for certain older sources.

11. Specifically, the CAA required that certain categories of existing major stationary sources built between 1962 and 1977 install BART as determined by the state. Kentucky finalized its initial Regional Haze SIP in June 2008 and revised it in 2010. EPA approved the 2008 Regional Haze SIP, as amended in 2010, in 2012.

12. EKPC has been diligent in monitoring the development of these federal environmental rules and has worked continuously to assess the impact that these new rules will have upon its generation fleet. As detailed below in Section IV of this Application, EKPC has begun the process of obtaining the necessary Project permit amendments from the Kentucky Division of Air Quality ("DAQ").

III. THE PROJECT

13. The Project emerged from the RFP as the clear least-cost option for EKPC to fulfill an anticipated future capacity need. The need for the future capacity was first identified in EKPC's 2012 Integrated Resource Plan ("2012 IRP"). The 2012 IRP identified the need for up to 300 MW of additional generating capacity by October 2015, primarily to comply with MATS. In order to comply with MATS, EKPC determined it would need to retrofit or retire both its Dale plant (200 MW) and Cooper Unit 1 (116 MW), both of which are coal-fired plants.

14. The RFP was issued on June 8, 2012 and was publicized in industry trade publications. The RFP requested proposals for conventional projects with a capacity of 50 MW

or more, or renewable projects with a capacity of 5 MW or more, and was directed towards utilities, power marketers, project owners and project developers. To facilitate the RFP, EKPC retained the Brattle Group ("Brattle") to serve as the Independent Procurement Manager ("IPM") for the RFP and to provide expertise in evaluating the proposals received. Moreover, because EKPC's Power Production business unit planned to submit one or more self-build options in the RFP, EKPC took appropriate steps to isolate the Power Supply business unit, which would receive and evaluate the bids, from the work of the Power Production business unit.

15. EKPC received over 100 different proposals from 65 different entities through the RFP. These proposals included proposals for new natural-gas fired power plants (some at existing EKPC sites and some at other locations); the sale of existing gas or coal-fired plants to EKPC; the sale of ownership interests in existing power plants; natural gas tolling agreements; energy-only contracts; capacity-only contracts; power purchase agreements for renewable energy resources or energy resources from coal waste and mine mouth methane.

16. After performing an initial evaluation of the bids received in the RFP, Brattle and EKPC's evaluation teams concluded that the Project clearly provided the most reasonable, least-cost option. The Project was developed by EKPC's Power Production business unit in consultation with the Burns & McDonnell engineering consulting firm. By making an investment of approximately $15 million, EKPC could retain 116 MW of existing capacity. The Brattle Group summarized its recommendation in a letter to EKPC's evaluation team on January 28, 2013. That letter was endorsed by EKPC's Senior Vice President for Power Supply, who provided further justification for the Project, in a letter to EKPC's President and Chief Executive

Officer on January 28, 2013. These letters are attached to this Application as Exhibit 1 and incorporated herein by reference.[1]

17. The justification for the Project is as follows:

- It provides the reasonable, least-cost option for securing future capacity for EKPC, with a net present value ("NPV") of over $50,000,000;
- Additional savings should be captured through efficiencies realized by continuing to operate both Cooper #1 and Cooper #2;
- EKPC may retain existing capacity without having to make a large capital investment, thereby furthering its goal of achieving greater financial strength through higher equity;
- EKPC is free to continue negotiating for other capacity options to fulfill the balance of its anticipated future capacity needs;
- EKPC has gained significant operational familiarity with the Cooper #2 AQCS and should be able to maximize its investment in that equipment by adding Cooper #1 to the air quality system;
- Operational efficiencies can continue to be achieved by operating two units at the Cooper Station; and
- EKPC will not be forced to make workforce reductions due to the closure of a generating unit.

18. The EKPC Board considered the IRP, RFP and the recommendations of EKPC's management and the analysis of the Brattle Group at several of its meetings. The EKPC Board authorized management to take the steps necessary to develop the Project, including the filing of

[1] Attached to this Application is a companion Motion for Confidential Treatment.

this Application, by adopting a Resolution on February 12, 2013. A copy of the Resolution from EKPC's Board of Directors approving the filing of this Application is attached as Exhibit 2 and incorporated herein by reference.

19. Because the Project does not satisfy the entirety of the anticipated 300 MW of future capacity needs, further evaluation was conducted on other bids received in the RFP. Brattle assisted EKPC's evaluation team in the development of a short list of other projects. Currently, EKPC is actively negotiating to satisfy the balance of the anticipated capacity need.

IV. REQUEST FOR APPROVAL OF A CPCN

20. Pursuant to 807 KAR 5:001, Section 15(2)(a), the facts relied upon to show that the Project is required for the public's convenience and necessity are as follows: EKPC must satisfy the environmental regulations described above; EKPC anticipates having a 300 MW future shortfall in generation capacity; the RFP conducted by EKPC demonstrates that the Project is the reasonable, least-cost option for satisfying a portion of this anticipated capacity shortfall; and the Project is needed to assure that EKPC can continue to provide adequate, efficient and reasonable service at fair, just and reasonable rates. The need for this Project is more fully described in the Direct Testimony of Anthony S. Campbell, EKPC's Chief Executive Officer and President, and the Direct Testimony of Jerry B. Purvis, EKPC's Director of Environmental Policy.

21. Pursuant to 807 KAR 5:001, Section 15(2)(b), EKPC states that it has submitted various federal and state permit applications which are outlined in detail in the Direct Testimony of Jerry B. Purvis. EKPC is working toward receipt of these permits and expects approvals in 2014

22. Pursuant to 807 KAR 5:001 Section 15(2)(c), a full description of the proposed location of the new construction, including a description of the manner in which same will be

constructed, is included in the Direct Testimony of Block Andrews, a Principal of Burns & McDonnell. There are no public utilities, corporations, or persons with whom the proposed new construction is likely to compete.

23. Pursuant to 807 KAR 5:001, Section 15(2)(d), one (1) copy of a map in electronic format and one (1) copy of a map in paper format to suitable scale showing the location of the proposed new construction are provided as Application Exhibit 3 and incorporated herein by reference. There are no facilities owned by others located anywhere within the map area.

24. Pursuant to 807 KAR 5:001, Section 15(2)(e), EKPC plans to finance the Project by utilizing Federal Financing Bank loan funds through a Rural Utilities Service-guaranteed loan.

25. Pursuant to 807 KAR 5:001 Section 15(2)(f), the estimated cost of construction is $15 million. Operations and maintenance ("O&M") costs associated with this project are estimated at $2.6 million annually. As detailed in the testimony of Block Andrews, the Project will allow EKPC to achieve greater efficiencies in O&M costs for the Cooper #2 AQCS.

26. The Project is needed and will not result in wasteful duplication. The Commission is therefore respectfully requested to issue a CPCN to EKPC as set forth herein.

V. REQUEST FOR APPROVAL OF ENVIRONMENTAL SURCHARGE COMPLIANCE PLAN AMENDMENT AND ENVIRONMENTAL SURCHARGE COST RECOVERY

27. Pursuant to KRS 278.183, EKPC is entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal in accordance with the utility's compliance plan. The Project meets the requirements of this statute. The applicability of KRS 278.183 is provided in the Direct Testimony of Isaac S. Scott, EKPC's Manager of Pricing.

28. Pursuant to KRS 278.183(2), EKPC has given thirty (30) days' advanced notice of its intent to file this Application to Amend its Environmental Compliance Plan and Environmental Surcharge. On July 3, 2013, EKPC provided such notice to the Commission, a copy of which is attached as Exhibit 4 and incorporated herein by reference. Also provided in Exhibit 4 is EKPC's notice to its member distribution cooperatives.

29. The estimated total capital cost of the Project is $14.95 million. The estimated total capital cost includes equipment and material costs of $7.50 million, capitalized labor costs of $3.11 million, indirect engineering and general costs of $2.61 million, contingency costs of $1.02 million, and project administration, temporary utilities, performance bond, and other associated owner's costs of $0.71 million.

30. EKPC is proposing that the return authorized for the other projects in its amended environmental compliance plan be applied to the Project. The return is composed of a Times Interest Earned Ratio ("TIER") component and an average cost of debt component. EKPC proposes that the TIER component be based on a 1.50 TIER, which the Commission approved in Case No. 2011-00032. EKPC proposes that the average cost of debt component be 4.057%. This reflects the average cost of debt as of December 31, 2012 and is consistent with the average cost of debt proposed in EKPC's most current six-month environmental surcharge review case, Case No. 2013-00140.

31. Once the Project becomes operational, EKPC estimates that the annual revenue requirement impact would be $3.60 million. This estimated annual revenue requirement translates into an increase of approximately 0.43% in the environmental surcharge for all customer classes at wholesale and would be passed through as an approximate 0.31% retail

increase. The estimated increase on an average residential customer's monthly bill would be approximately $0.27.

32. The inclusion of the Project in the approved Environmental Surcharge Compliance Plan will not require any revisions to EKPC's Rate ES – Environmental Surcharge.

33. The Project qualifies for surcharge recovery under KRS 278.183. Accordingly, EKPC respectfully requests the Commission to allow it to amend its Environmental Surcharge Compliance Plan to include the Project and to recover the costs associated with the amended Environmental Surcharge Compliance Plan through EKPC's existing environmental surcharge mechanism.

VI. OVERVIEW OF TESTIMONY

34. In support of this Application, EKPC is tendering the Direct Testimony of several witnesses, including:

a. Mr. Anthony S. Campbell, EKPC's President and Chief Executive Officer, will offer Direct Testimony describing EKPC's strategic goals, the relationship of the Project to those goals, the nature of the Project, and the need for it. His testimony is attached hereto as Exhibit 5 and incorporated herein by reference.

b. Mr. Jerry B. Purvis, EKPC's Director of Environmental Policy, will offer Direct Testimony describing the environmental rules under which EKPC must operate, their impact upon EKPC's future capacity resources, EKPC's current permitting activities and EKPC's current environmental compliance plan. His testimony is attached hereto as Exhibit 6 and incorporated herein by reference.

c. Ms. Julia J. Tucker, EKPC's Director of Planning, will offer Direct Testimony describing the conclusions in EKPC's 2012 IRP, the process for developing and evaluating EKPC's RFP, and the justification for the Project. Her testimony is attached hereto as Exhibit 7 and incorporated herein by reference.

d. Mr. James Read, a Principal with the Brattle Group, will offer Direct Testimony describing the role of the Brattle Group in the RFP process, the evaluations performed by himself and others at the Brattle Group and his recommendation to EKPC's evaluation team. His testimony is attached hereto as Exhibit 8 and incorporated herein by reference.

e. Mr. Block Andrews, a Principal with Burns & McDonnell will offer Direct Testimony describing the technical aspects of the Project. His testimony is attached hereto as Exhibit 9 and incorporated herein by reference.

f. Mr. Isaac S. Scott, EKPC's Manager of Pricing, will offer Direct Testimony describing the cost of the Project, EKPC's position with regard to the return that should be earned on the Project, the financing plan for the Project, how the proposed amendment to the environmental compliance plan will be implemented on a monthly basis and the rate impact at the wholesale and retail levels. Mr. Scott will also describe the proposed revisions to the monthly environmental surcharge reporting forms. His testimony is attached hereto as Exhibit 10 and incorporated herein by reference.

VII. CONCLUSION

WHEREFORE, on the basis of the foregoing, EKPC respectfully requests the Commission to:

(1) Issue a Certificate of Public Convenience and Necessity, pursuant to KRS 278.020(1), for the Project;

and

(2) Authorize EKPC to amend its Environmental Compliance Plan, pursuant to KRS 278.183, and allow EKPC to recover the costs associated with the amended Environmental Compliance Plan through its existing environmental surcharge mechanism.

Dated at Winchester, Kentucky, this 21st day of August 2013.

VERIFICATION

The undersigned, pursuant to KRS 278.020(1), KRS 278.183, 807 KAR 5:001, Sections 14 and 15, and other applicable law, hereby verifies that all of the information contained in the foregoing Application is true and correct to the best of my knowledge, opinion and belief.

East Kentucky Power Cooperative, Inc.

BY: Don Mosier

ITS: EVP & COO

COMMONWEALTH OF KENTUCKY

COUNTY OF CLARK

The foregoing Verification was signed, acknowledged and sworn to before me this 21st of August 2013 by Don Mosier of East Kentucky Power Cooperative, Inc., a Kentucky corporation, on behalf of the corporation.

NOTARY PUBLIC, Notary # ______

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

Respectfully submitted,

Mark David Goss
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Counsel for East Kentucky Power Cooperative, Inc.

LIST OF EXHIBITS

The Brattle Group

Cambridge
San Francisco
Washington
London
Madrid
Rome

Confidential
Contains Information Subject to Non-Disclosure Agreements Between EKPC and Bidders

January 28, 2013

Mr. David Crews
Senior Vice President of Power Supply
East Kentucky Power Cooperative
4775 Lexington Road
Winchester, Kentucky 40392

Dear Mr. Crews:

The Brattle Group was engaged by the East Kentucky Power Cooperative to provide consulting services in connection with its 2012 Request for Proposals (the "RFP") for long-term power supplies—specifically, to assist EKPC develop and market the RFP, screen proposals, select a Short List, and report on a recommended course of action. This was a collaborative effort in which Brattle leveraged EKPC's power supply planning staff, analytical resources, and data. In this letter I summarize the development and marketing of the RFP, describe the selection of the Short List, and discuss the factors germane to EKPC in making its final selection.

Background

The 2012 RFP was an outgrowth of a planning process that culminated in EKPC's submission of an Integrated Resource Plan to the Kentucky Public Service Commission in April of 2012 (the "2012 IRP"). The 2012 IRP identified the need for up to 300 MW of additional generating capacity by October 2015, primarily to comply with the Mercury and Air Toxics Standards (MATS) issued by the Environmental Protection Agency in December 2011. Specifically, EKPC determined that it will need to retrofit or retire both its Dale plant (200 MW) and Unit 1 at its Cooper plant (116 MW), both of which are coal-fired. EKPC has a history of building and operating its own power plants, but it decided to pursue an RFP process so that it could consider a full range of power supply options, including power purchase agreements and purchase of power plants from third parties.

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Brattle and EKPC began the engagement in May with a meeting at EKPC's offices in Winchester, Kentucky. The principal topics at this meeting were the goals and timetable for the RFP, the types of supply options EKPC would be willing to consider, the creation of a web site to serve as the locus for the RFP process, and the news that EKPC expected to be integrated into the PJM Interconnection RTO prior to the target October 2015 in-service date.

EKPC said that it was willing to consider proposals to purchase new or existing power plants, to enter into intermediate-term or long-term power supply contracts, and to purchase power from renewable or conventional resources. EKPC identified a target start date of October 2015 for new resources but said it would consider proposals that specified earlier or later dates. The only strict constraints that EKPC imposed on the supply proposals were that they (a) specify a term of at least five years and (b) specify no less than 50 MW if for power from conventional generation resources and no less than 5 MW if for power from renewable generation sources.

The Request for Proposals

The next steps were to write and disseminate the Request for Proposals. EKPC and Brattle assembled a list of potentially interested parties. Among others this included a list of firms that had expressed interest after EKPC announced its intention to issue an RFP in a press release on April 23, 2012. Brattle simultaneously built a web site through which interested parties could obtain the RFP and RFP calendar, register to receive RFP updates, submit questions ("ask the manager"), obtain required forms, and submit their proposals. The web site was also used to post answers to questions thought to be of general interest ("frequently asked questions").

The RFP was released and the web site went "live" on June 8. Interested parties were encouraged to register to ensure they received updates to the RFP requirements and schedule. Registration did not entail an obligation to bid, however. Prospective bidders were required to submit a non-binding Notice of Intent to Bid and Confidentiality Agreement by July 3, 2012.

The Rural Utilities Service (RUS) instructed EKPC to post notices of the RFP in three national energy publications. EKPC posted notices in the *Public Utilities Fortnightly*, Platt's *Megawatt Daily*, and SNL *Power Daily*. The advertisements were published on or around the week of June 25, 2012.

In addition to creating the RFP web site, Brattle conducted an informational Webinar for potential bidders on June 27.

As part of the RFP, EKPC offered to make available three of its own sites for construction of "turnkey" power plants. Specifically, EKPC stated that it would shoulder certain infrastructure costs, such as transmission, fuel hook ups, and environmental permits. EKPC offered to allow

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prospective visitors to visit the sites, but it required visitors first to execute a Confidentiality Agreement. A form for this purpose was posted to the RFP website on or about June 28, 2012.

Proposals in response to the RFP were due in electronic format by August 30, 2012, followed by hard copy five days later.

Proposals Received in Response to the RFP

EKPC received a large and diverse set of proposals in response to the RFP. These included proposals for new natural-gas fired power plants, some at existing EKPC sites, others outside of EKPC; proposals to sell EKPC existing gas or coal-fired plants, or ownership shares thereof; natural gas tolling agreements, with rights to the associated capacity as well as energy; power purchase agreements with contract price terms linked to the owner's operating costs ("cost-based PPAs"); energy-only contracts for "block" products, with liquidated damages provisions; capacity-only contracts; PPAs for power from renewable energy resources, including wind, solar, biomass, landfill gas, and waste; and proposals for energy from coal waste and mine mouth methane.

In addition to the proposals received from third parties, EKPC's Production Engineering & Construction (PE&C) group prepared proposals to build new natural gas-fired power plants and to retrofit some of its existing coal units. We refer to these as the "self-build options".

Most of the proposals specified start dates or commercial operation dates of October 2015, which was given in the RFP as the time at which EKPC would need to replace certain existing generation. However, some proposals specified earlier or later contract start or facility on-line dates. Proposals for power purchase agreements had terms as short as five years and as long as 30 years. In total EKPC received over 100 proposals from 65 bidders.

Selection of the Short List

Prior to considering proposals The Brattle Group verified that proposals were from qualified bidders (by virtue of having submitted a Notice of Intent to Bid) and that the bidders had submitted the other required forms.

Proposals were evaluated under the assumption that EKPC will be integrated into PJM by the beginning of the planning period. As a PJM member EKPC's load obligations and supply portfolio will effectively be separated—EKPC will (a) schedule its load with PJM and (b) bid its generation into PJM on a daily basis. EKPC will pay PJM for the energy, capacity, and ancillary services its owner-ratepayers consume. EKPC will receive payments from PJM for the energy, capacity, and ancillary services it produces. (Energy in PJM is priced on a nodal basis. Capacity is priced on a locational deliverability area ("LDA") basis.)

EKPC's objective in selecting power supply resources is to meet its supply obligations at the lowest expected cost, consistent with maintaining system reliability and bearing an acceptable amount of risk. The minimum-cost criterion can be captured by a net present value (NPV) metric: the present value of the energy and capacity the resources offered by a proposal can be expected to provide less the present value of the costs that would be incurred to obtain the energy and capacity. If the proposal is for the purchase of a power plant, this means comparing the market value of the energy and capacity the plant will produce to the costs of purchasing, owning, and operating the plant. If the resource is a power purchase agreement, it means comparing the market value of energy and/or capacity it will provide to the payments required under the contract. The difference between the value of energy and capacity on the one hand and the cost incurred to obtain that energy and capacity on the other—the NPV—is an estimate of the *value added* by a supply proposal. The value added corresponds to the *reduction* in the present value of expected net power supply costs to EKPC members if the proposal were accepted.

The initial evaluation procedure was to place each proposal into a category consisting of proposals with similar characteristics. The following categories were used:

- PPAs for power from conventional (or unspecified) energy resources—most of the power purchase agreements offered are structured as tolling agreements or call options or provide some degree of dispatch flexibility. The energy output will tend to be greater under contracts with high heat (i.e., energy conversion) rates than those with low heat rates. Proposals for high heat rate resources were put in a separate category from proposals with low heat rates.

- Ownership of generation resources—as distinct from the contractual obligations of a PPA—would entail an up-front investment of funds and thus associated financing requirements. Ownership would also entail management responsibilities (e.g., operation and maintenance).

- PPAs for power from solar and wind generation resources are intermittent supplies—when available, they would provide a flow of energy subject to ambient weather conditions (e.g., wind speed and sunshine).

- PPAs for power from other renewable energy resources (landfill gas, waste, biomass) have the character of baseload resources—they typically would produce energy approximately equally over the diurnal and seasonal cycles.

- Self-build proposals were put in a separate category. The self-build options are qualitatively distinct from the other proposals EKPC is considering. If EKPC were to enter into a contract with a third party, it would be able to negotiate performance provisions to protect itself in the event of a cost overrun, delay, etc. If EKPC chooses a self-build option, it will not have the ability to obtain comparable assurances.

The principal selection criterion for the Short List was the net present value of the proposals. The net present value (NPV) of a PPA was calculated as the present value (PV) of forecast energy revenues plus the PV of forecast capacity payments less the PV of fixed and variable contract payments. The NPV of facility purchase and sale proposals was calculated as the PV of net energy (energy revenues less fuel and variable operating and maintenance (O&M) costs) plus the PV of capacity payments less the PV of fixed O&M costs and the purchase price. In addition to NPVs themselves, we examined NPVs scaled for the size and duration of the proposals, that is, the NPVs per megawatt-year.

Initial evaluations were based on the information the bidders provided in their proposals. This includes capacity, heat rates, and non-fuel operating and maintenance costs. It also includes forecast energy output of intermittent (wind and solar) and baseload resources. In some cases bidders did not provide complete estimates of non-fuel operating costs (e.g., they omitted the fixed O&M costs). In those cases we used estimates based on data for similar equipment. Other inputs to the initial evaluations were:

- Energy Prices: Forecasts of commodity market prices (electric energy, natural gas, and coal) were obtained by EKPC from [redacted] The electricity prices are for delivery to the AEP Dayton hub—the nearest trading hub to EKPC. Our understanding is that [redacted] constructs its price forecasts using a combination of forward market prices (to the extent available) and price forecasts.

- Capacity Prices: PJM capacity prices through the 2015/16 delivery year were determined in previous PJM auctions. (The PJM delivery year begins on June 1 and ends May 31.) Forecasts of capacity prices for subsequent delivery years were calculated by escalating the PJM 2015/16 forward price at the rate of [redacted]%/year.

- Capacity Credits: Conventional generation resources in PJM receive credit for unforced capacity (UCAP)—the summer rated capacity of the resource adjusted for availability. Our understanding is that PJM assigns a credit of 38% for solar generation capacity and 13% for wind generation. We assigned capacity credit of 85% to other renewable generation resources.

- Renewable Energy Credits: Kentucky has not established renewable portfolio standards. However, EKPC estimates that it could realize value of approximately $[redacted]/MWh for renewable energy credits (RECs) from solar energy and approximately $[redacted]/MWh for RECs from wind and other renewable resources. These REC values were escalated at a rate of [redacted]%/year for evaluation purposes.

Energy production provided by intermittent and baseload generation was estimated using the forecasts bidders supplied in their respective proposals. (The value of the forecast output of wind and solar proposals was not adjusted to account for the intermittent quality of the associated energy.) Energy production for dispatchable generation and power purchase agreements was calculated using production cost analysis in conjunction with data provided in proposals (e.g., heat rates and variable O&M costs). EKPC used the RTSim commercial software package for the production cost simulations.

Brattle and EKPC selected six proposals for the Short List by identifying the proposal in each category with the highest NPV per MW-year. In addition, EKPC chose to include a seventh proposal in the Short List. The key features of the Short List proposals are summarized below.

[redacted] Purchase of New Natural Gas Facility

[redacted] has proposed to build a combined cycle natural gas-fired generating facility at the J. K. Smith site. [redacted] This is based on a specified schedule of installment payments and does not include cumulative interest expense through the project completion date. The proposed on-line date is June 1, 2016 assuming a Notice to Proceed by February 1, 2014. [redacted] would act as the overall Developer for the design, management, procurement, and construction process. [redacted] would act as the EPC Contractor to design and construct the facility. [redacted] offered to provide guarantees and liquated damages to be negotiated for in-service date, heat rate, output, and standard warranties.

[redacted] PPA for Renewable Generation

[redacted] has proposed a 20-year power purchase agreement for [redacted] This proposal has a positive NPV when the forecast energy output is treated as if it was firm for valuation purposes.

[redacted] PPA for Coal Waste Facility

[redacted]

[redacted]

[redacted]Natural Gas Tolling Agreement

[redacted]

[redacted]PPA for Gas-Fired Generation

[redacted]

EKPC Self-Build Option—Cooper Unit No. 1 Scrubber

EKPC Production Engineering & Construction (PE&C) proposes to retrofit Cooper Unit No. 1, specifically, to utilize the circulating dry scrubber recently installed on Unit No. 2 at Cooper to treat the exhaust gas from Cooper Unit 1. This would allow Unit 1 to operate at its full design capacity of 116 MW (net) and to comply with the Mercury and Air Toxics Standards and Best

Available Control Technology. PE&C estimates that the retrofit will result in an increase of $4.50/MWh in the variable O&M costs of Unit 1 with no impact on heat rates, start costs, fixed O&M costs, availability, or forced outage rates of Unit 1 or Unit 2. However, this project will limit the operational flexibility of the units at Cooper. Due to the fact that the scrubber will be shared by the units, the operation of the units will have to be carefully coordinated. The greatest impact to unit operation will be when only Unit 1 is in operation. During that time, Unit 1 will be restricted to a minimum load of approximately 100 MW in order for the scrubber to continue operation. PE&C estimates that the cost of this retrofit will be $14,702,000 and it projects a completion date of June 13, 2014.

[redacted]

[redacted]

Evaluation & Final Selection of Proposals

EKPC's objective is to acquire power supply resources that will minimize expected power supply costs while maintaining reliability and acceptable risk exposures. The minimum-cost objective is captured by the net present value (NPV) criterion, which was the primary criterion for selecting proposals for the Short List. NPV is not a sufficient criterion, however, because of the diversity of the power supply options available to EKPC. The candidate supply options differ in the following salient respects:

- Duration: The proposals range from a 5-year PPA to the purchase of a new power plant with a potential economic life well in excess of 25 years.

- Investment Requirement: In contrast to a power purchase agreement, the acquisition of a power plant would require that EKPC make a substantial upfront investment of funds.

- Generation Feedstock: Proposals include coal-fired, natural gas-fired, and renewable generation resources, which would present different commodity market risk exposures for EKPC's members.

- Heat Rate: Proposals include some resources with a high heat rates and others with low heat rates. Heat rates have implications for both the duty cycle of a resource (i.e. peaking vs. cycling vs. baseload) and for market risk exposure. (The term "heat rate" refers to the energy conversion rate of a generation resource or analogous term in a power supply contract. It is the rate at which fuel is converted to power.)

Choosing among proposals will require EKPC management to make judgments about the value and risk associated with these factors—value and risk that cannot readily be monetized and incorporated in a single NPV metric. The following discussion highlights considerations germane to the final selection of supply proposals by EKPC.

Resource Mix

EKPC is a predominantly coal-fired electric utility—about two thirds of its generation capacity is coal-fired and one third is natural gas-fired. Its gas generation consists of combustion turbine units used chiefly for peaking service. EKPC also owns several landfill gas facilities and purchases hydro power from the Southeastern Power Administration. As a result, over 80 percent of its energy supply is coal-based. Due largely to the decline in natural gas prices, coal-fired generation has become less competitive and gas-fired generation more competitive, a consequence of which is that the power market as a whole has a substantial and increasing amount of natural gas in the generation mix. Substantial retirements of coal-fired generation are also anticipated in response to EPA regulations. This is the market in which the energy prices EKPC's members will pay are set when EKPC is integrated into PJM. Also, over the long term, gas-fired generation is less exposed than coal to the possibility that carbon emissions will be priced or taxed. Therefore, shifting the EKPC supply portfolio towards gas-fired generation would be desirable from the standpoint of hedging its members' exposures to market risks.

Intermittent Resources

Kentucky does not have renewable portfolio standards, and EKPC considers proposals for renewable energy on the same basis as energy produced by conventional generation resources. That is, it does not assign extra value to renewables beyond what it expects to realize through trading any associated renewable energy credits. Furthermore, energy produced by wind and solar resources is intermittent and thus qualitatively different from energy produced by conventional resources. When evaluating proposals for the Short List, the value of the forecast energy from wind and solar resources was not discounted to reflect its intermittent quality. Therefore, the NPVs for the intermittent proposals overstate their value added to EKPC in relation to the NPVs of proposals for conventional resources.

[redacted]

Operating in PJM

Historically EKPC has built and operated its generation fleet to serve the power requirements of its members. Its wholesale power transactions have been limited by transmission constraints. Joining PJM means a fundamental change in the way EKPC operates its system. To reiterate, EKPC's load obligations and supply portfolio will effectively be separated—EKPC will pay PJM for the energy, capacity, and ancillary services its members consume and PJM will pay EKPC for the energy, capacity, and ancillary services it produces. A major benefit to being in PJM is that the transmission constraints under which EKPC has been operating will be relaxed, allowing it to operate its fleet and serve its load more efficiently. EKPC will learn through experience how to bid its resources into the market and how those resources will be utilized by PJM; how much power flows into and out of its system; how transmission congestion and losses vary across nodes within its load zone; and so forth. [redacted]

Uncertainty

Of course, the back drop to a long-term power supply decision is uncertainty—uncertainty about load growth, uncertainty about power and fuel market prices, and uncertainty about the related issues of demand response, environmental regulation, and renewable energy. The last five years has been a sea change in competition between coal and natural gas generation. At this point there is little to suggest that this shift in inter-fuel competition is temporary. Environmental laws and regulation remain in flux. With rapid technological change, the potential for demand response to diminish requirements for new capacity only increases. And as one looks further into the future, the probability that a tax (or equivalent) will be levied on carbon emissions increases. [redacted]

[redacted]

Risk of Self-build

If EKPC chooses a self-build option, then it will run the risk that the cost to complete the project will exceed the amount estimated by PC&E, that it will take more time to complete, and/or that it will fail to perform as anticipated. In contrast, if EKPC pursues a contract with a third party, it can seek to negotiate contract provisions that provide protection from the consequences of these events. Thus, there is a drawback to self-build options: EKPC cannot bind itself to itself. It must self-insure against this class of risks. This means that a self-build proposal needs to have a higher expected value added than an otherwise comparable proposal from a third party.

Vetting the Short List

The EKPC-Brattle project team held one or more meetings or teleconferences with each of the bidders following their selection for the Short List. This is a summary of our assessments to date. I first discuss the short-list proposals that we have either eliminated from further consideration or "put on the back burner", then discuss the proposals we are continuing to pursue.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Cooper Unit 1 Retrofit: The proposed retrofit of Cooper Unit 1 appears to be the single most attractive proposal when viewed on a stand-alone basis. A modest investment—estimated by PE&C to be $15 million—would yield 116 MW of coal fired generation capacity. This is $127/kW, which stands in contrast, e.g., to [redacted] Over a ten-year time horizon—that is, assuming that the plant would not provide energy margins or capacity revenues more than ten years after completion—the retrofit has an NPV of over $50 million. This does not reflect additional reductions in operating costs that EKPC anticipates will be realized with both Unit 1 and Unit 2 of Cooper in service. And even if it did not produce any electric energy over this time horizon, the retrofit of Cooper 1 would be a break-even NPV investment at forecasted capacity market revenues. On the other hand, the Cooper 1 retrofit does not further EKPC's strategic goal to diversify its power supply portfolio. It would leave EKPC with 116 MW more coal-fired capacity than it would have if Cooper 1 was retired, and thus with that much more capacity exposed to coal market price risk and the potential for a carbon tax and/or carbon regulations.

Conclusions & Recommendations

When it is integrated into PJM, EKPC's load will be scheduled with and served by PJM resources. EKPC will not be required by PJM to acquire its own power supply resources. A decision to acquire additional power supply resources is an option for EKPC—an option it can exercise if it finds a resource that can add value in the PJM markets.

Our analysis indicates that four of the proposals selected for the Short List have positive NPVs: [redacted] the Cooper 1 retrofit (116 MW), [redacted]

The Cooper 1 retrofit would provide 116 MW of capacity, well under the 300 MWs specified in the RFP. Therefore, EKPC may also wish to consider a complementary proposal. [redacted]

Our analysis of the revised proposals thus far indicates that [redacted] economically attractive and superior to the [redacted]

To sum up, our analysis indicates that the proposed Cooper 1 retrofit would add very substantial value for a modest investment. Based on my understanding of EKPC's objectives, constraints, and circumstances, it is the proposal with the highest value added for EKPC. [redacted]

Sincerely,

James Read
Principal

JAR:eb

cc: David Samford, Esq.

REDACTED

EAST KENTUCKY POWER COOPERATIVE

January 28, 2013

Tony Campbell
President and Chief Executive Officer
East Kentucky Power Cooperative
4775 Lexington Road
Winchester, KY 40391

RE: Endorsement of Recommendation Received from the Brattle Group in Relation to the 2012 Request for Proposals for up to 300 MW of Capacity and Energy

Dear Mr. Campbell:

EKPC's 2012 Integrated Resource Plan ("IRP") contained four steps in its "Recommended Plan of Action". One of those steps was "EKPC will issue an RFP for Power Supply resources to address the existing capacity affected by the EPA MATS rules". In May 2012, the Power Supply Business Unit hired Brattle Group ("Brattle") to assist EKPC with its solicitation and evaluation of power supply opportunities in an independent and unbiased manner. The solicitation was structured to make Dale Station and Cooper 1 Mercury and Air Toxic Standards ("MATS") compliance costs compete with other power supply options that the market would provide. Brattle completed an extensive solicitation and evaluation process, which is defined and summarized, along with its findings and conclusions to date, on the attached letter report. All of the proposals were judged against the forward market to determine the value they each provided.

The Cooper 1 retrofit option has been determined by Brattle to be the highest value-added option available to EKPC on a stand-alone basis. Moreover, the retrofit preserves the existing capacity that could potentially be lost at Cooper Station; however, it does not address the anticipated capacity loss at Dale Station. The economic results indicate that "the proposed Cooper 1 retrofit would add very substantial value for a modest investment" and "is the proposal with the highest value added for EKPC."

Having reviewed Brattle's analysis and recommendations – and based upon our experience, knowledge and belief – it is our recommendation that EKPC should immediately move forward with the Cooper 1 retrofit and while continuing to evaluate and negotiate [redacted] the remaining short list bidders. In addition to the economic benefits cited in Brattle's report, we believe that other reasons support this recommendation. First, retrofitting Cooper 1 allows EKPC to further utilize the investment it has already made in the scrubber at that plant. Lime use will be better optimized and the average cost will be slightly less per unit with both units being serviced by the existing scrubber. Second, it allows EKPC to continue operating two units at an existing plant site which lends itself to more efficient operations overall as compared to only one unit at the

REDACTED

site. Third, it also allows EKPC to retain the technical expertise of the staff at the Cooper Plant, which benefits other EKPC operating plants. Finally, proceeding with both Cooper 1 and [redacted] None of these outcomes have been factored into Brattle's economic analysis, but they all favor moving forward with the Cooper 1 retrofit. While Brattle's statement that retaining the Cooper 1 capacity "does not further EKPC's Strategic goal to diversify its power supply" is accurate, this risk is no greater than what EKPC is currently facing by operating Cooper 1 and [redacted]. It should be noted that Cooper 1 represents only 4% of EKPC's total generating capacity thus the overall impact on EKPC's fuel diversity is minimal.

Although there is some risk in proceeding with the Cooper 1 retrofit before [redacted] it is a certainty that the Cooper 1 retrofit will require EKPC to modify certain operating permits and could trigger additional regulatory actions. In order to meet the MATS deadlines, we believe that EKPC needs to move forward immediately with this project. Therefore, I recommend that we move forward with the Cooper 1 retrofit project, by asking the Board of Directors to approve it, and to continu[redacted].

I would also like to give you a brief update on our [redacted]

Brattle and the Power Supply Business Unit recognize that proceeding forward with both the Cooper 1 retrofit and [redacted] EKPC however will retain the option to stop negotiations with the remaining short list bidders at any time and reserve the ability to reassess the market through a new RFP.

Regards,

David Crews
Senior VP, Power Supply

REDACTED

**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, February 12, 2013, at 9:30 a.m., EST, the following business was transacted:

Review and Request Approval of Cooper 1 Retrofit Project for Partial Fulfillment of the EKPC 2012 RFP

After review of the applicable information, a motion to approve the Cooper 1 Retrofit Project for Partial Fulfillment of the EKPC 2012 RFP, was made by Strategic Issues Committee Chairman Lonnie Vice, and passed by the full Board to approve the following:

Whereas, on June 8, 2012 East Kentucky Power Cooperative, Inc. ("EKPC") issued an All Source Long-term Request for Proposals ("RFP") to obtain new resources through a solicitation of interest from utilities, power marketers, project owners and project developers to meet minimum qualifications for acquisition of up to 300 megawatts ("MW") of new resources consistent with EKPC's Integrated Resource Plan ("IRP") filed with the Kentucky Public Service Commission ("PSC") on April 20, 2012;

Whereas, EKPC received over 100 proposals from 65 bidders including 82 PPAs, 27 Facility Ownerships and 7 self-build proposals from the EKPC Power Production business unit as a result of the RFP; and 55 of these proposals were renewable energy PPAs and projects including solar, wind, landfill gas-to-energy, biomass, and waste-to-energy proposals;

Whereas, the consultant retained by EKPC to evaluate the proposals received through the RFP and EKPC's Power Supply business unit have both concluded that the self-build option of retrofitting the existing Cooper 1 unit to utilize the circulating dry scrubber recently completed on the Cooper 2 unit – at a cost of approximately $15 million – was the single most attractive proposal when viewed on a stand alone basis; and

Whereas, [redacted]; and

Whereas, the regulatory and environmental requirements for implementing the Cooper 1 Retrofit Project will require significant time and should begin as quickly as possible; now, therefore, be it

<u>Resolved,</u> that the EKPC Board of Directors approve the implementation of the Cooper 1 Retrofit Project ("Project"), and hereby authorize the President and Chief Executive Officer or his designee, to: (1) file for any and all required or advisable certificates, permits and applications with regulatory and environmental agencies of the Commonwealth of Kentucky and the United States Government for the Project; (2) initiate steps to develop an agreement for the design, procurement, and construction management for the Project; (3) authorize a loan application for the Project; (4) amend the 3-Year Construction Work Plan to include the Project accordingly; (5) take any and all other steps necessary to implement the Project that are consistent with the above-described actions.

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 12th day of February 2013.

A. L. Rosenberger
A. L. Rosenberger, Secretary

Corporate Seal

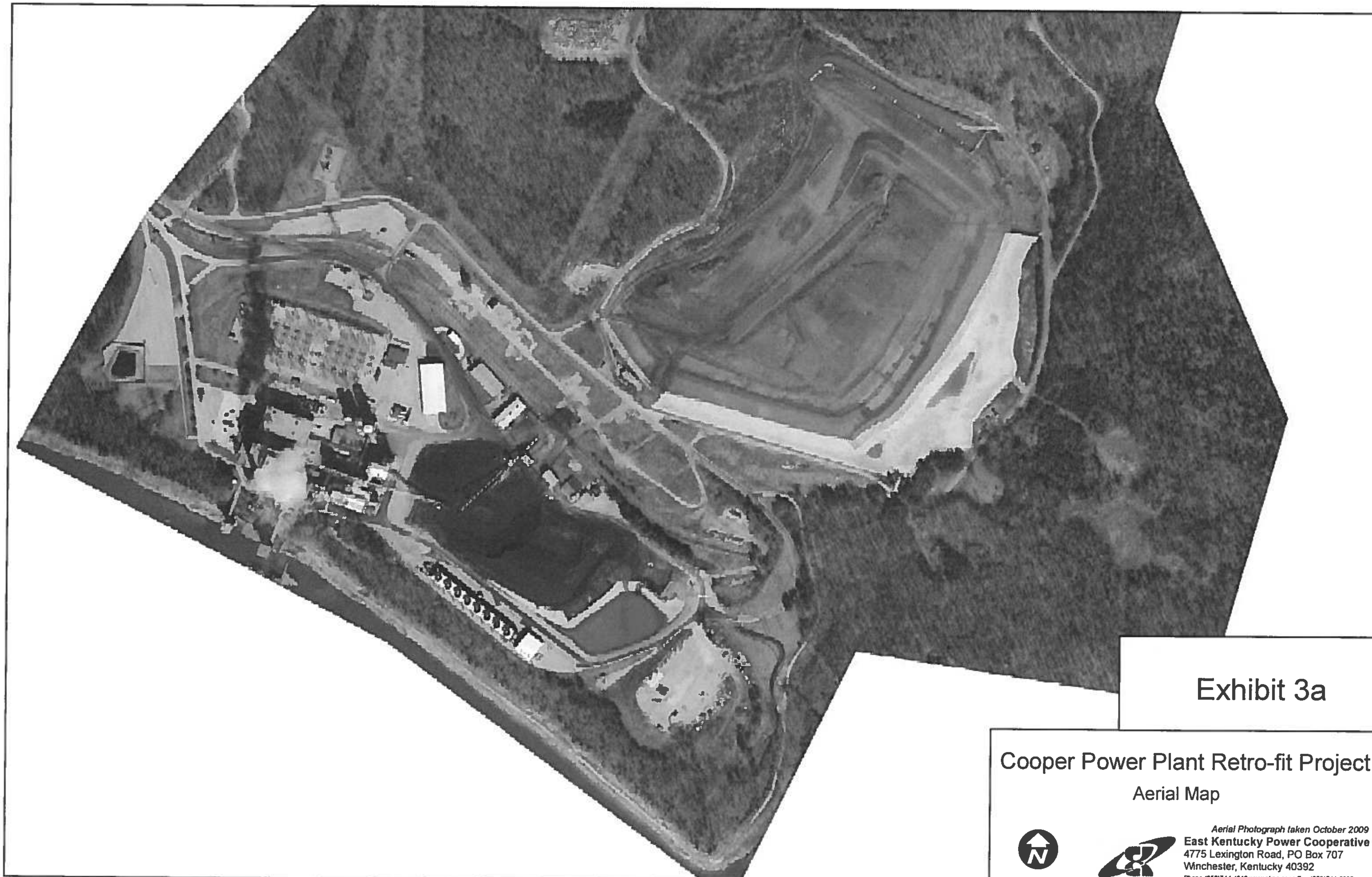


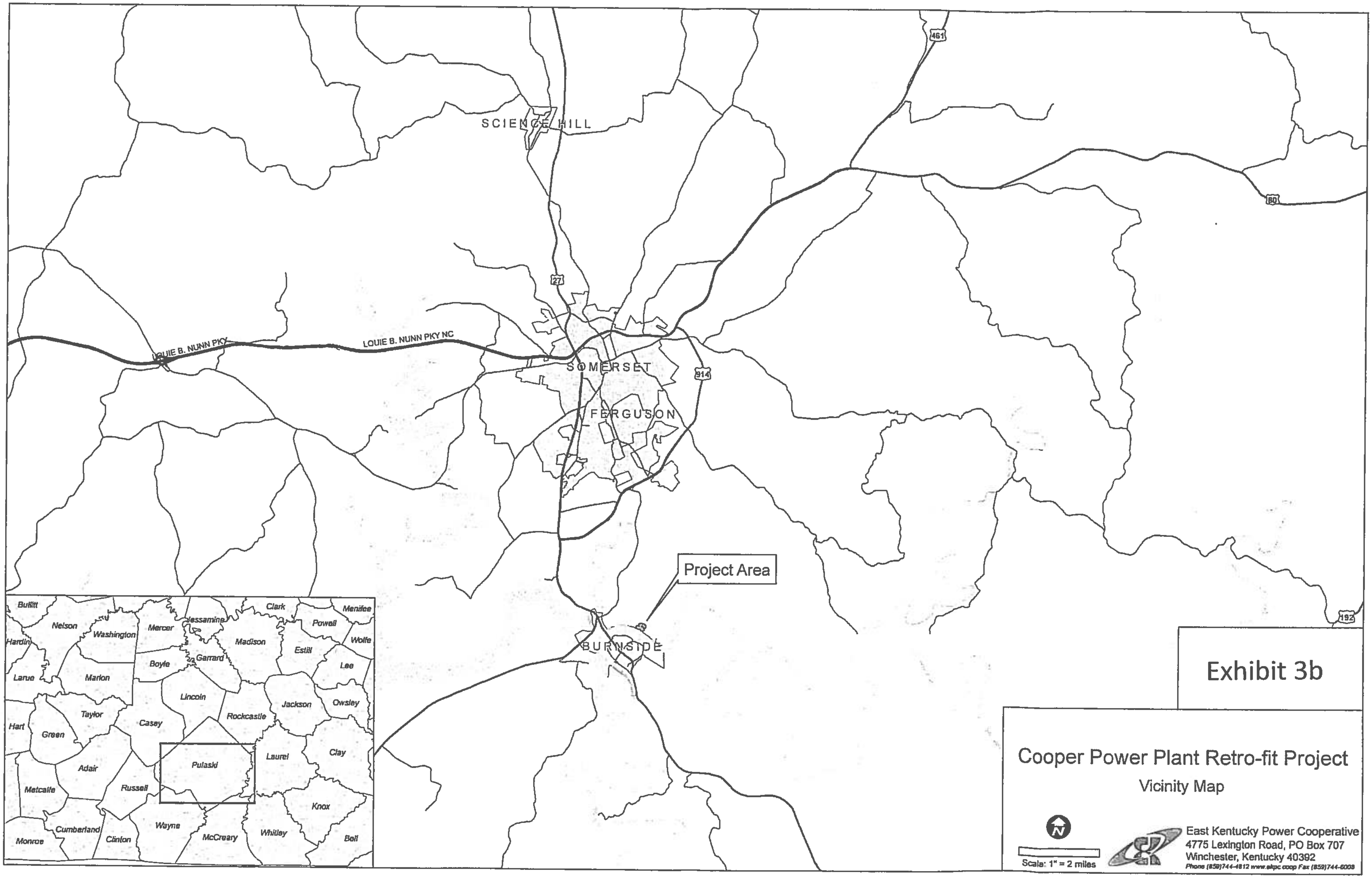
Exhibit 3a

Cooper Power Plant Retro-fit Project

Aerial Map

Aerial Photograph taken October 2009

East Kentucky Power Cooperative
4775 Lexington Road, PO Box 707
Winchester, Kentucky 40392
Phone (859)744-4812 www.ekpc.coop Fax (859)744-6008



SCIENCE HILL
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Washington
Mercer
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Menifee
Powell
Hardin
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Estill
Wolfe
Boyle
Garrard
Lee
Larue
Marion
Lincoln
Jackson
Owsley
Taylor
Casey
Rockcastle
Hart
Green
Pulaski
Laurel
Clay
Adair
Russell
Metcalfe
Knox
Cumberland
Wayne
Monroe
Clinton
McCreary
Whitley
Bell
Exhibit 3b
Cooper Power Plant Retro-fit Project
Vicinity Map
Scale: 1" = 2 miles
East Kentucky Power Cooperative
4775 Lexington Road, PO Box 707
Winchester, Kentucky 40392

Exhibit 3c

Cooper Power Plant Retro-fit Project

Aerial Photograph

Aerial Photograph taken October 2009

East Kentucky Power Cooperative
4775 Lexington Road, PO Box 707
Winchester, Kentucky 40392
Phone (859)744-4812 www.ekpc.coop Fax (859)744-6008

Goss • Samford PLLC
Attorneys at Law

Exhibit 4a

Mark David Goss
mdgoss@gosssamfordlaw.com

July 1, 2013

RECEIVED
JUL 3 2013
PUBLIC SERVICE COMMISSION

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
P.O. Box 615
Frankfort, Kentucky 40602

Dear Mr. Derouen:

East Kentucky Power Cooperative, Inc. ("EKPC") hereby gives notice pursuant to KRS 278.183(2) of its intent to file an Application under KRS 278.183. This Application will request approval of:

1. An Amended Environmental Surcharge Compliance Plan;
2. A Revised Environmental Surcharge to Recover the Costs of this Amended Plan; and
3. A Certificate of Public Convenience and Necessity Pursuant to KRS 278.020(1) for the Cooper 1 Duct Reroute Project.

EKPC plans to file this Application on or after August 1, 2013.

We respectfully request that the following parties representing EKPC be included on the Commission's Service List in this proceeding:

Mark David Goss
David S. Samford
2365 Harrodsburg Road, Suite B325
Lexington, KY 40504

Patrick Woods
East Kentucky Power Cooperative, Inc.
P. O. Box 707
Winchester, KY 40392-0707

If you have any questions or require additional information, please contact me.

Very truly yours,

Mark David Goss

cc: Hon. Jennifer B. Hans
Hon. Michael L. Kurtz

M:\Clients\4000 - East Kentucky Power\1500 - 2012-360 Environmental Mechanism-CPCN\Correspondence\Ltr. to Jeff Derouen - 130701

EAST KENTUCKY POWER COOPERATIVE

Exhibit 4b

MEMORANDUM

TO: Member System CEO's

FROM: Anthony S. Campbell *Anthony S. Campbell*

DATE: July 5, 2013

SUBJECT: Notice of Amendment to EKPC Environmental Compliance Plan

On Wednesday, July 3, EKPC gave notice to the Commission of its intent to file an Application for an Approval of an Amendment to its Environmental Compliance Plan and Environmental Surcharge. The notice also indicated EKPC would be seeking a Certificate of Public Convenience and Necessity. EKPC plans to file this Application on or after Monday, August 5.

The amendment will enable EKPC to recover costs associated with installing and operating nearly $15 million in equipment designed to reduce pollution. If approved, we would begin recovering these costs in stages around the time that the equipment becomes operational.

The new compliance project is at the Cooper station and will route the exhaust gas from Cooper Unit 1 into the Air Quality Control System already installed on Cooper Unit 2.

If approved, once the project becomes fully operational in 2016, the request is expected to amount to an increase of about 0.25 percent in the environmental surcharge for all customer classes at wholesale, and would be passed through as an approximate 0.18 percent retail increase, which would be an estimated $0.16 on the average residential bill. The increase would be phased in as project is built and begins operation. The PSC has until March 2014 to rule on EKPC's request.

This project is necessary in order for our power plants to meet increasingly stringent environmental standards.

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

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)))))))))	CASE NO. 2013-00259

EXHIBIT 5

DIRECT TESTIMONY OF ANTHONY S. CAMPBELL

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 21, 2013

Q. Please state your name, business address, and occupation.

A. My name is Anthony S. Campbell and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am President and Chief Executive Officer ("CEO") of EKPC.

Q. Please state your education and professional experience.

A. I received a Bachelor of Science degree in electrical engineering from the University of Southern Illinois at Carbondale and a Masters of Business Administration from the University of Illinois at Champaign. I have been employed by EKPC since June 2009. Prior to joining EKPC, I served as CEO of Citizens Electric Corporation, an electric transmission and distribution cooperative located in southeast Missouri.

Q. Please provide a brief description of your duties at EKPC.

A. The Board of Directors has given me, as CEO, the responsibility for managing the Cooperative's business on a day-to-day basis. I develop and recommend to the 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 in this proceeding?

A. The purpose of my testimony is to present an overview of EKPC's Application for a Certificate of Public Convenience and Necessity ("CPCN") for the proposed duct reroute project at the John Sherman Cooper Unit 1 ("Project"). I will also present an overview of

EKPC's request to amend its existing environmental compliance plan to include the Project and to allow for cost recovery of that project through EKPC's environmental surcharge mechanism.

Q. Could you briefly describe how EKPC reached the conclusion it should undertake the Project?

A. The decision to undertake the Project has its origins in the 2012 Integrated Resource Plan ("2012 IRP") filed with the Commission in April 2012. The 2012 IRP identified the need for up to 300 MW of additional generating capacity, primarily to comply with the Mercury and Air Toxics Standards ("MATS") issued by the Environmental Protection Agency in December 2011. In order to consider a full range of options to address this need, EKPC decided to pursue a Request for Proposals ("RFP") process. The RFP was issued on June 8, 2012 and responses were due August 30, 2012. EKPC received a large and diverse set of proposals in response to the RFP. After analyzing and evaluating the proposals, it was concluded that the Project was the most cost effective and reasonable option.

Q. Could you briefly describe how this RFP process is consistent with EKPC's strategic plan and goals?

A. One of the strategic objectives contained in EKPC's strategic plan concerns generation and transmission, where EKPC is committed to carefully manage its portfolio of assets and pursue economically prudent diversity concerning supply resource and ownership. The use of a RFP process encouraged responses from the greatest number of potential partners while also providing an excellent proxy for any self-build options that our Power Production business unit may have been able to develop. That diversity and fresh-look at the market, we felt, would give our Board the most valuable and credible information to make decisions about EKPC's future generation portfolio.

Q. Could you briefly describe how the Project is related to this strategic objective?

A. When our evaluation team and consultant had completed their work, the value proposition for the Project was very compelling. Although the Project does not help us achieve one of our strategic objectives, which is to diversify our fuel portfolio, it helps us leverage existing resources well into the future. The benefits that we recognize through the Project will take the form of maximizing the value of past investments, achieving greater operating efficiencies in the future and retaining a skilled workforce. All of these things will help us to continue our progress towards long-term financial stability.

Q. Could you briefly describe the Project?

A. The Project will combine the exhaust gas from Unit 1 with the exhaust gas from Cooper Unit 2 and route those gases through the Air Quality Control System ("AQCS") installed on Cooper Unit 2 in 2012. The AQCS includes a dry flue gas desulfurization system along with an integral pulse jet fabric filter. By combining the exhaust gases from both units and routing this through the AQCS, EKPC will achieve compliance with MATS and the Regional Haze State Implementation Plan ("Regional Haze SIP") particulate emission limitation and Best Available Retrofit Technology ("BART") requirement for both Cooper Unit 1 and Unit 2. EKPC retained Burns & McDonnell to assist in the development of the Project. EKPC and Burns & McDonnell have determined that the AQCS has adequate capacity to handle the combined exhaust gases and satisfy the applicable environmental emission limits.

Q. Could you briefly describe EKPC's request to amend its existing environmental compliance plan to include the Project and to allow cost recovery through EKPC's environmental surcharge?

A. EKPC's original environmental compliance plan was approved in Case No. 2004-00321,[1] the first amendment to the environmental compliance plan was approved in Case No. 2008-00115,[2] and the second amendment to the environmental compliance plan was approved in Case No. 2010-00083.[3] The Project provides for compliance with MATS, the Regional Haze SIP, and BART, all federal environmental requirements that EKPC believes are eligible for inclusion in the environmental compliance plan as described in KRS 278.183(1). EKPC believes that the Project is reasonable and represents a cost-effective means for compliance with the applicable federal environmental requirements. Consequently, EKPC believes the proposed amendment to the environmental compliance plan should be approved and cost recovery of the Project through EKPC's environmental surcharge mechanism should be authorized.

Q. Does this conclude your testimony?

A. Yes it does.

---

[1] Case No. 2004-00321, Application of East Kentucky Power Cooperative, Inc. for Approval of an Environmental Compliance Plan and Authority to Implement an Environmental Surcharge, final Order dated March 17, 2005.

[2] Case No. 2008-00115, Application of East Kentucky Power Cooperative, Inc. for Approval of an Amendment to Its Environmental Compliance Plan and Environmental Surcharge, final Order dated September 29, 2008.

[3] Case No. 2010-00083, Application of East Kentucky Power Cooperative, Inc. for Approval of an Amendment to Its Environmental Compliance Plan and Environmental Surcharge, final Order dated September 24, 2010.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	**CASE NO. 2013-00259**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Anthony S. Campbell, 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.

Anthony S Campbell

Subscribed and sworn before me on this 21st day of August, 2013.

Gwyn M. Willoughby
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	**CASE NO. 2013-00259**

EXHIBIT 6

DIRECT TESTIMONY OF JERRY B. PURVIS

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 21, 2013

Q. Please state your name, business address, and occupation.

A. My name is Jerry B. Purvis and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Director of Environmental Affairs for EKPC.

Q. Please state your education and professional experience.

A. I received a B.S. degree in Chemistry from Morehead State University and a B.S. degree in Chemical Engineering from the University of Kentucky. I also received a Master of Business Administration from Morehead State University. I have been employed by EKPC for approximately 19 years serving in various positions. In 2011, I became the Director of Environmental Affairs at EKPC.

Q. Please provide a brief description of your duties at EKPC.

A. As Director of Environmental Affairs, I am responsible for the preparation of permits for generation stations and landfills as well as the preparation of supplemental environmental impact statements under the National Environmental Policy Act. I have also been responsible for the development of the environmental compliance plans for the EKPC, one of which includes a compliance plan for New Source Review under the Environmental Protection Agency ("EPA") regulations. I report directly to the Chief Operating Officer/Executive Vice President.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe and discuss the environmental regulations applicable to the proposed duct reroute project at the John Sherman Cooper Unit 1 ("Project"). I will also address the Title V air permit revision submittal for the project.

Q. Is the Project required under the provisions of the New Source Review Consent Decree ("Consent Decree")?

A. The Project is not required under the Consent Decree between EKPC and the United States of America, entered in Civil Action Number 5:04-cv-00034-KSF in the United States District Court for the Eastern District of Kentucky on September 24, 2007. However, the proposed project does tie Cooper Unit 1 into the Air Quality Control System ("AQCS") installed on Cooper Unit 2, which EKPC elected to install under the Consent Decree.

Q. Could you briefly describe the components of the Cooper Unit 2 AQCS and what is controlled by the AQCS?

A. The Cooper Unit 2 AQCS consists of a Selective Catalytic Reduction system using aqueous ammonia injection and catalyst, a dry Circulating Fluidized Bed Flue Gas Desulphurization ("dry FGD") unit using hydrated lime reagent, and a pulse jet fabric filter ("PJFF"). Ancillary systems (e.g., storage silos, day bins, hydrators, vacuum systems) were added to manage ash and the reagent materials. The project also required the addition of draft fans, a new air heater, boiler adjustments, and expansion of various electrical and control systems to incorporate the new equipment. The AQCS was designed to achieve compliance with the specific requirements set forth in the Consent Decree for control of sulfur dioxide ("SO_2") and nitrogen oxide ("NOx"). While not required by the Consent Decree, the AQCS includes the PJFF for control of Particulate Matter ("PM") emissions in order to meet Best Available Retrofit Technology ("BART") as determined by the Kentucky Division of Air Quality ("DAQ") and reflected in the Kentucky Regional Haze State Implementation Plan ("Regional Haze SIP") as amended in 2010.

Q. Could you identify the applicable environmental regulations addressed by the proposed Project?

A. The proposed Project is designed to achieve compliance with the Regional Haze SIP PM emission limitation and the BART requirements for both Cooper Unit 1 and Unit 2, and applicable provisions of the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units codified at 40 CFR Part 63, Subpart UUUUU (Mercury and Air Toxics Standards ("MATS")).

Q. Could you describe the Regional Haze SIP limitations and the BART requirements?

A. The 1977 amendments to the Clean Air Act ("CAA") created a program for protecting visibility of Class I areas, such as national parks. In 1990, Congress added Section 169B to the CAA to address regional haze issues. The EPA promulgated regulations in 1999 to address regional haze, which required Kentucky and other states to prepare Regional Haze SIPs. The states were also required under the CAA to evaluate the use of retrofit controls for certain older sources. Specifically, the CAA required that certain categories of existing major stationary sources built between 1962 and 1977 install BART as determined by the state. Kentucky finalized its initial Regional Haze SIP in June 2008 and revised it in 2010. EPA approved the 2008 Regional Haze SIP, as amended in 2010, in 2012.[1]

The Cooper Units 1 and 2 are BART-eligible sources and share a common stack. EKPC initially submitted its BART determination and control strategy to the Kentucky DAQ in 2007. The initial control strategy proposed by EKPC was a wet FGD and wet electrostatic precipitator as BART for PM compliance for the units. The 2008 Regional Haze SIP identified BART for Cooper Units 1 and 2 as wet FGD and wet electrostatic precipitator with a filterable PM emission limit of 0.030 lb/MMBtu. EKPC requested an

[1] The EPA did include a limited disapproval of the Regional Haze SIP due to the plan's reliance on the Clean Air Interstate Rule.

amendment to the Regional Haze SIP in 2009, citing additional analysis and its determination that a dry FGD and a PJFF control system would be an equivalent and preferred alternative to the wet control system originally proposed. The Kentucky DAQ reviewed the request and agreed to the change. The 2010 amendment to the Regional Haze SIP states that the BART for Cooper Units 1 and 2 is dry FGD and PJFF technology and the BART emission limit is a filterable PM emission rate of 0.030 lb/MMBtu.[2] Because the Regional Haze SIP BART PM limit determination established an emission limit and the most stringent technology option, EPA found that Kentucky had appropriately addressed BART for Cooper Units 1 and 2.

Q. Could you describe how the Regional Haze SIP limitations and the BART requirements are addressed in the Project?

A. The Project is proposing to combine the Cooper Unit 1 exhaust gas with the Cooper Unit 2 exhaust gas and utilize dry FGD and PJFF technology to provide the necessary level of BART control. This approach will provide compliance with the BART requirement in the Regional Haze SIP that Cooper Units 1 and 2 achieve a filterable PM emissions rate of 0.030 lb/MMBtu and utilize dry FGD and PJFF as the control technology. No change to the emission limit or BART technology is being proposed, so the proposed approach is consistent and complies with the approved Regional Haze SIP.

Before the Cooper Unit 1 exhaust gas is processed through the Cooper Unit 2 dry FGD and PJFF, it will have already been subjected to control through the existing Cooper Unit 1 electrostatic precipitator ("ESP"). EKPC has determined that the Cooper Unit 2 dry FGD and PJFF system has adequate capacity to control the exhaust gas from Cooper

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[2] The change from a wet control system to a dry control system was discussed in the Commission's May 1, 2009 Order in Case No. 2008-00472, where the Commission granted EKPC a Certificate of Public Convenience and Necessity to construct the Cooper Unit 2 AQCS; see pages 3 through 6 of the Order.

Units 1 and 2 to meet the 0.030 lb/MMBtu emission rate for PM. Currently the dry FGD and PJFF technology is operating such that PM emissions are approximately one order of magnitude below the BART Regional Haze SIP PM limit, thus demonstrating the capacity to accept and adequately treat the additional gas flow from Cooper Unit 1 after it exits the existing Cooper Unit 1 ESP. EKPC is also proposing to utilize longer bags in the PJFF, which will result in improved control.

On June 3, 2013, the Kentucky DAQ informed EKPC that the proposed Project was consistent with and complied with the 2008 Kentucky Regional Haze SIP, as amended. A copy of finding by the Kentucky DAQ is attached to my testimony as Exhibit JBP-1.

Q. Could you describe MATS and how it is addressed in the Project?

A. EPA published the final MATS rule in the Federal Register on February 16, 2012. MATS requires new and existing coal and oil-fired electric generating units ("EGUs") to meet emission limits for three categories of pollutants: mercury, acid gases, and non-mercury hazardous air pollutant ("HAP") metals. MATS allows EGUs to comply with a filterable PM emission limit as a surrogate for all non-mercury HAP metals. In addition, MATS requires coal-fired EGUs to comply with a hydrogen chloride emission limit as a surrogate for all acid gases, except that EGUs equipped with a wet or dry flue-gas desulfurization or dry sorbent injection system and a SO_2 continuous emission monitoring systems ("CEMs") may comply with a SO_2 emission limit instead. MATS allows existing sources to demonstrate compliance with these emission limits either through quarterly stack testing or using CEMs.

The Project will allow Cooper Unit 1 to achieve compliance with the MATS emission limits by adding the dry FGD and PJFF system to the Cooper Unit 1 control train. Cooper Unit 1's emission will be controlled by the low NOx burners and ESP presently installed on Unit 1 and then vented through the dry FGD and PJFF system. This combination of controls will allow Cooper Unit 1 to achieve compliance with the MATS filterable PM, acid gases, and mercury emission limits. New CEMs will also be installed to monitor emissions for purposes of demonstrating compliance with MATS.

Q. Will the Project require EKPC to seek any extensions or permitting amendments?

A. Yes. MATS requires affected existing sources to comply with the rule by April 16, 2015. However, the CAA contains a procedure by which existing sources may obtain a one-year compliance extension to April 16, 2016 from the state permitting authority. The preamble to the MATS rule provides that one-year compliance extensions shall be "broadly available" from state permitting agencies. By letter dated June 24, 2013 EKPC submitted a request to the Kentucky DAQ for a one-year compliance extension for the Project. A copy of this request is attached to my testimony as Exhibit JBP-2. On July 24, 2013 the Kentucky DAQ granted the compliance extension request for Cooper Unit 1 and a copy of this letter is attached to my testimony as Exhibit JBP-3.

On March 25, 2013 EKPC submitted an application to the Kentucky DAQ for a significant revision to the Cooper Title V permit to implement the Project. The application is currently under review by the Kentucky DAQ. A copy of the application is attached to my testimony as Exhibit JBP-4.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBITS

Document	Exhibit
DAQ Regional Haze SIP Finding (June 3, 2013)	1
EKPC Request for One Year Extension of Compliance Deadline (June 24, 2013)	2
DAQ Granting One Year Extension of Compliance Deadline (July 24, 2013)	3
EKPC Cooper Title V Air Permit Revision Application (March 25, 2013)	4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	**CASE NO. 2013-00259**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Jerry B. Purvis, 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.

Jerry B. Purvis

Subscribed and sworn before me on this 21st day of August, 2013.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

Steven L. Beshear
Governor

Leonard K. Peters
Secretary

Energy and Environment Cabinet
Department for Environmental Protection
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601-1403
Web site: air.ky.gov

June 3, 2013

Mr. Jerry Purvis, Director
Environmental Affairs
East Kentucky Power Cooperative
P.O. Box 707
Winchester, Kentucky 40392-0707

Dear Mr. Purvis:

The Kentucky Division for Air Quality (Division) has reviewed your March 15, 2013, letter and attachments, regarding the implementation of Best Available Retrofit Technology (BART). In the submittal, East Kentucky Power Cooperative (EKPC) requests confirmation from the Division that EKPC's project for BART implementation at the Cooper Station is consistent with the Kentucky Regional Haze State Implementation Plan (SIP) and BART determination by the Division.

Based on the Division's review of EKPC's submittal, the Division finds that EKPC's proposed project for BART implementation at the Cooper Station is consistent and complies with the Kentucky Regional Haze SIP and the Division's BART determination for Cooper Units 1 and 2 (*Pursuant to the June 25, 2008, Kentucky Regional Haze SIP and as amended on May 28, 2010*). In addition, the Division concurs that additional BART determination modeling for the Cooper Station is not necessary. If you have any questions regarding this matter, please contact Mr. Martin Luther, of my staff, at martin.luther@ky.gov or 502-564-3999.

Respectfully,

Sean Alteri for

John S. Lyons
Director

JSL/mrl

EAST KENTUCKY POWER COOPERATIVE

June 24, 2013

Via Certified and Electronic Mail 7006 3450 0002 3279 7599

John Lyons
Director
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601

Re: John Sherman Cooper Power Station (AI 3808)
MATS Compliance Extension Request for Unit 1

Dear Mr. Lyons:

Pursuant to Section 112(i)(3)(B) of the Clean Air Act and 40 CFR 63.6(i)(4)(i)(A), East Kentucky Power Cooperative, Inc. (EKPC) hereby requests a one-year extension of the compliance date for the National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units, also known as the Mercury and Air Toxics Standards (MATS), promulgated at 40 CFR Part 63, Subpart UUUUU. Specifically, EKPC requests the extension of the compliance date from April 16, 2015 to April 16, 2016 for Cooper Unit 1. As presented in more detail below, the extension is necessary to complete the permitting, engineering, installation and testing of the Cooper 1 Reroute Project, which will provide additional control for Cooper Unit 1 so the unit will be able to meet MATS.

A. Background

EKPC is a not-for-profit generation and transmission electric utility cooperative headquartered in Winchester, Kentucky. EKPC's purpose is to generate electricity and transmit it to member cooperatives for distribution to retail consumers. Today, EKPC provides wholesale energy and services to sixteen distribution cooperatives through power plants, peaking units, hydro power, and more than 2,800 miles of transmission lines. In turn, the member cooperatives supply energy from EKPC to 520,000 homes, farms, and businesses across 87 counties in Kentucky. EKPC is owned, operated, and governed by its members who use the energy and services EKPC provides.

In the MATS preamble, EPA stated that one year compliance extensions under Section 112(i)(3)(B) "should be broadly available to enable a facility owner to install controls within 4 years if the 3 year time frame is inadequate for completing the installation." 77 Fed. Reg. 9410. In light of EPA's pronouncement and consistent with EKPC's obligations as a utility regulated by the Kentucky Public Service Commission (KPSC) to provide reliable power to its member cooperatives and consumers, EKPC has been evaluating the additional controls that will be needed for the units in its fleet to comply with MATS. The Division previously communicated to the utility sector that requests for extensions should be accompanied by specific plans to achieve compliance and anticipated timelines, rather than preliminary assessments of compliance options and general concerns about timing. Accordingly, EKPC has worked to evaluate compliance options for Cooper 1 and, based on its selection of a specific path forward and the time necessary for implementation, submits this request for a one-year extension.

B. Compliance Plan for Unit 1 to Meet MATS

Cooper Unit 1 is an existing pulverized coal-fired, dry-bottom, wall-fired boiler equipped with an electrostatic precipitator (ESP) and low NOx burners. As you know, Cooper Unit 1 shares a common stack with Cooper Unit 2. Cooper Unit 2 is an existing pulverized coal-fired, dry-bottom, wall-fired boiler equipped with low NOx burners, Dry Flue Gas Desulfurization (DFGD) system, Selective Catalytic Reduction (SCR), Pulse Jet Fabric Filter (PJFF) and Fuel Solv Treatment. The DFGD was recently installed on Cooper Unit 2 pursuant to the consent decree entered in *United States v. East Kentucky Power Cooperative, Inc.*, Civil Action No. 04-34-KSF (E.D. Ky.) and the PJFF was recently installed to satisfy Best Available Retrofit Technology (BART) requirements. Since publication of the MATS rule on February 16, 2012, EKPC and Burns & McDonnell have analyzed various options for control of Unit 1 emissions and have determined that the Unit 2 DFGD/PJFF control train has adequate capacity to handle the Cooper Unit 1 exhaust gas following the Unit 1 ESP. Thus, by utilizing those recently added controls for both Unit 1 and Unit 2, EKPC will be able to achieve compliance with the MATS requirements at both units.

C. Demonstration

Pursuant to 40 CFR 63.6(i)(6)(i), EKPC provides the following specific information in support of its request.

1. *Description of Controls to be Installed to Comply with MATS*

As summarized above, EKPC will reroute the exhaust gas from Cooper Unit 1 after the ESP to the DFGD and PJFF that currently control only the Cooper Unit 2 exhaust gas. (See diagram provided in Attachment 1.) EKPC will combine the Unit 1 exhaust gas from the induced draft (ID) fan with the Unit 2 exhaust gas prior to the DFGD. Implementation will result in the DFGD, PJFF, existing Unit 2 ID fan, and DFGD/PJFF minimum flow recirculating damper being common components to Unit 1 and Unit 2. This will necessitate installation of new ductwork from the Unit 1 ID fan to the Unit 2 ductwork tie-in location, new exhaust gas regulation and isolation dampers, integration of the controls systems, and new CEMS equipment. The DFGD/PJFF equipment will incorporate a modified hydrated lime feed system including modifications to allow dual hydrator operation. It is anticipated that longer fabric filter bags and cages will be installed in the PJFF to support increased gas flow.

2. *Project Schedule*

From publication of the rule in February 2012 until February 2013, EKPC and Burns & McDonnell conducted certain privileged feasibility studies to determine the most appropriate MATS control system for Unit 1. On February 12, 2013, the EKPC Board of Directors approved the above described control option at Unit 1. However, the EKPC Board reserved authorization for construction contract award until receipt of the necessary final Title V Permit revision, after the EPA objection period has closed and the permit revision is considered final. EKPC immediately began preparation of its application for the significant revision of the Title V permit, and the application was submitted to the Division on March 25, 2013.

Issuance of the revised Title V permit is crucial to completion of this project. For purposes of this request, EKPC has conservatively estimated that the time necessary for review, public comment, response to public comment and issuance of a final permit will take approximately 14 months. EKPC bases its estimate on the following factors: 1) EKPC submitted a revision request necessary to install the emissions controls and ancillary equipment for Unit 2 on July 10, 2009. The Division issued the final permit on September 29, 2010 (review time of 14 months, 19 days); 2) EKPC submitted an application for renewal of the Title V Permit for Cooper on July 8, 2011. On May 13, 2013 EKPC received the proposed permit, which is under EPA review prior to issuance of the final permit (review period of approximately 24 months). The average review period for these two prior permitting actions is 19 months; therefore, a conservative estimate of 14 months for review and issuance of the final revised Title V permit is reasonable. Should the review period extend beyond the estimated 14 months, the schedule below will require adjustment.[1]

Further, although the project will result in an overall significant emissions reduction, the associated changes necessitate EPA review and concurrence due to the impacts on consent decree compliance. EKPC and Region 4 have discussed consent decree compliance in light of the project, and EPA is presently evaluating a compliance solution that EKPC has proposed. While EPA is reviewing the proposal, in an effort to avoid delay, EKPC is simultaneously pursuing the necessary changes to its Title V permit through its March 25, 2013 application for a significant revision under Section 16 of 401 KAR 52:020. As noted in the application, EPA concurrence with the proposed changes is of course a prerequisite for the revision of any necessary requirements in the permit. The schedule provided below includes these approval steps. In addition, MATS is currently being litigated in the United States Court of Appeals for the District of Columbia Circuit, the outcome of which could impact the project schedule, if changes are made to the rule.

March 2013 – May 2014: Permit revision application review and issuance of final permit.

March 2013 – Summer 2013: EPA approval of consent decree monitoring change.

June 2014 – December 2015: Upon issuance of the final permit by the Division, EKPC will be in a position to authorize Burns & McDonnell to proceed with the detailed engineering design for the project. The detailed engineering design work will be the basis for developing bid packages for the construction, as well as providing key information needed for equipment procurement. Bid packages will be prepared and sent to capable vendors. Bids will be evaluated

[1] The compliance schedule herein demonstrates that even if a final permit revision could be issued within an unlikely 6 month period and the 18 month period for engineering design, equipment procurement and project construction began in December, 2013, the project could not be completed by the April 16, 2015 MATS compliance date.

and vendors selected to perform the work. Under the authority of the Board, EKPC management will then authorize the selection of bid winners to begin work. EKPC will then proceed with contracting and ordering of necessary equipment. On-site work will begin after contracting is completed and necessary equipment is received, with construction scheduled to be completed during a month-long outage at Unit 1 and 2 in December 2015. Given the scope and complexity of the project, and the coordination necessary, the 18-month schedule to complete this part of the project is reasonable.

December 2015: Based on recommendations from Burns & McDonnell, and the requirements of the Regional Transmission Organization (RTO), PJM Interconnection (PJM), an outage is planned for December, 2015 to tie in the Cooper 1 new ductwork, dampers, emission monitors, fans and other ancillary equipment to complete the integration of Unit 1 with Unit 2. In addition, several modifications will have to be made to the distributed control system (DCS) to ensure safe and reliable boiler operation. EKPC, under the control of PJM, has limited ability to choose outages and timing. PJM will not allow EKPC to take scheduled maintenance outages during its peak season from June 1 – September 30, of each year. Therefore, under the PJM obligations for peak season, EKPC is limited to outages only during the off-peak seasons. In addition, PJM and EKPC require 12 months prior notification to modify planned outage schedules.

January 2016 – March 2016: Start-up, shakedown and commissioning of both units with common controls will occur during this period. Startup and commissioning activities for a common operating unit's draft system requires a well-planned approach to ensure that equipment is operating as the design intends. This includes the verification of critical draft components such as the draft regulating dampers, draft fans, and their associated control logic. In addition, the components of the combined air quality control system operation must be characterized for various operating scenarios. The characterization of these components requires requests for load changes that must be coordinated with dispatch. Also, safety is of paramount importance and thus is a priority for this project. In addition to compliance with environmental regulations, EKPC is committed to meeting the Boiler Code and Fire Marshal regulations. This scheduled time will allow EKPC to follow Burns & McDonnell recommendations to check, trouble shoot and confirm proper operation including the following steps: 1) in accordance with the Boiler Code and Fire Marshall regulations, perform several logistical DCS checks; 2) verify and confirm proper operation of fans and dampers; 3) verify and confirm safe and reliable operation of the modified DCS; 4) verify and confirm safety interlocks for the boilers, dampers, and fans; and, 5) perform the necessary checks and verifications of the environmental control and monitoring equipment to ensure safe, accurate and reliable operation. These activities will assure both compliance and safety for operation of Cooper Station.

April 16, 2016: Commercial operation begins with Unit 1 in compliance with MATS requirements.

EKPC expects to file the notification of intent to the KPSC for a Certificate of Public Convenience & Necessity (CPCN) for this project in July 2013. This notification will set forth required regulatory action by the KPSC to make a determination in accordance with KPSC regulations for a CPCN and an Environmental Surcharge (ESC). The receipt of the CPCN will be required before EKPC can proceed with the project.

D. Additional Considerations

Although not a specific element of the demonstration required by 40 CFR 63.6(i)(6)(i), EPA and the states have recognized the potential for MATS impact on transmission reliability with a particular focus on localized impacts. Although EKPC has provided proper justification for this extension under the general provisions of 40 CFR Part 63, it must also be noted that Cooper Units 1 and 2 are key components of the transmission system supplying power to southern Kentucky. As shown above, the project schedule for providing control on Cooper 1 will not allow the unit to achieve MATS compliance by April 16, 2015. If Cooper 1 is required to cease operation from April 16, 2015 until the control project is complete, the unavailability of Cooper 1 would create localized transmission issues for southern Kentucky. Specifically, if Cooper 1 is unable to operate and Cooper 2 encountered a problem and had to shut down during periods of hot weather and high loads, overloads and instability of the transmission system supplying power to the area are forecasted to result. An upgrade of the transmission system to help address such a contingency is under evaluation. However, the upgrade would be required on the LGE/KU system and thus, is not within EKPC's control. EKPC is uncertain as to the timeline for that project. The requested extension of the MATS compliance date will allow EKPC to continue to operate both Cooper units pending completion of the work on controls for Cooper 1 and will reduce the risk to local end-use consumers.[2]

E. Conclusion

As discussed above, EKPC has been diligent in its identification and assessment of compliance options for Cooper Unit 1 since publication of the MATS rule. Upon selection of the compliance approach, EKPC promptly began the permitting process necessary to implement the control option determined to be most appropriate. The schedule presented above for installation of the chosen control option is reasonable, and EKPC has provided justification for the timeline presented. EKPC has demonstrated that it meets the criteria for the grant of an extension and requests that the Division grant a one-year extension of the MATS compliance date for Unit 1, to April 16, 2016.

If you have any questions regarding this submittal please contact me at (859) 745- 9244.

Sincerely yours,

Jerry Purvis

Jerry Purvis
Director of Environmental Affairs

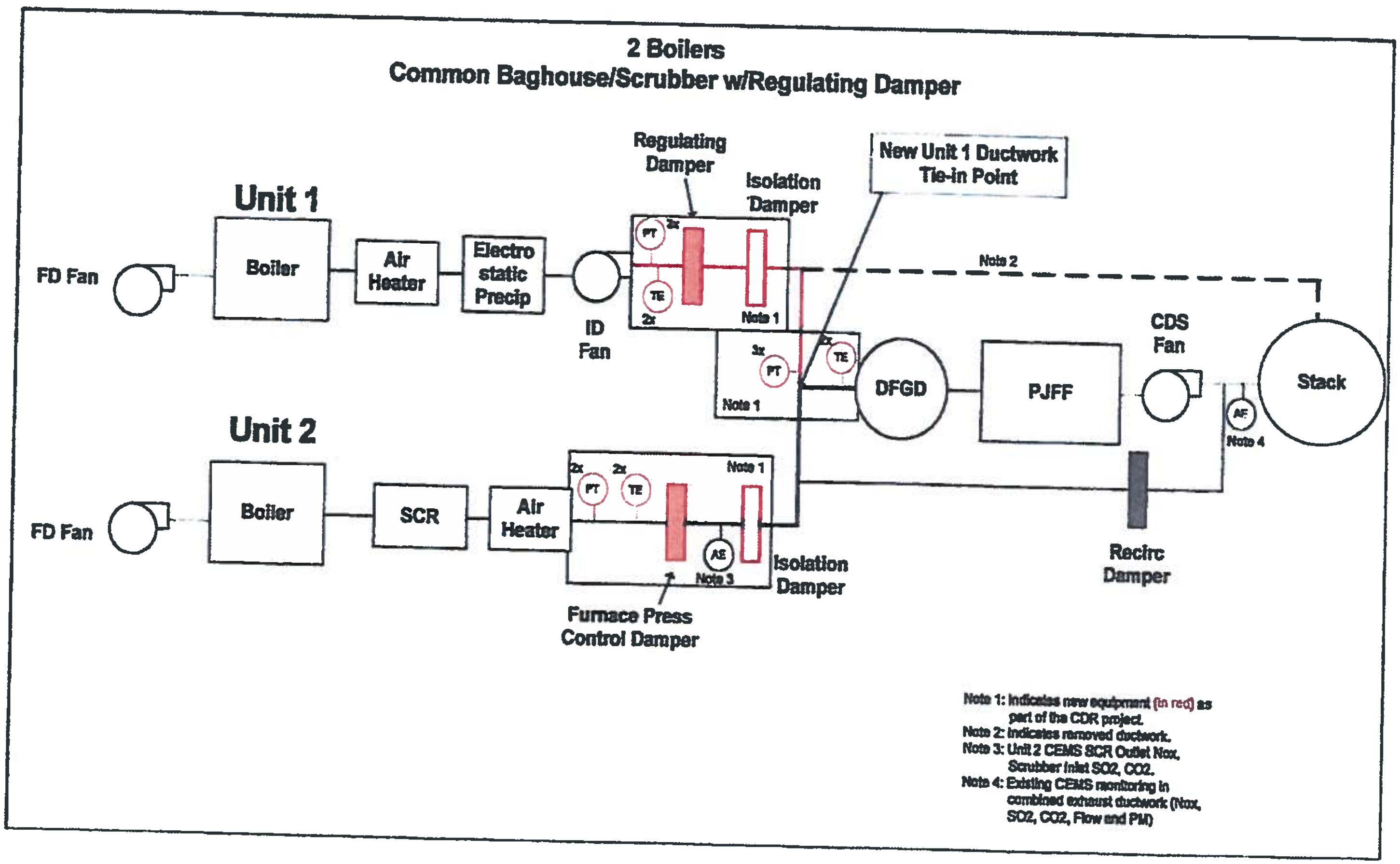
---

[2] While the single point of failure concern will exist after the project is complete, this MATS extension will allow additional time for the transmission upgrade to be performed to mitigate reliability concerns.

cc: Sean Alteri
Jackie Quarles
Ben Markin
Louis Petrey
Carolyn Brown

Attachment

ATTACHMENT 1


2 Boilers
Common Baghouse/Scrubber w/Regulating Damper
Unit 1
Unit 2
FD Fan
Boiler
Air Heater
Electro static Precip
ID Fan
Regulating Damper
Isolation Damper
New Unit 1 Ductwork Tie-in Point
Note 2
Note 1
DFGD
PJFF
CDS Fan
Stack
Note 4
FD Fan
Boiler
SCR
Air Heater
Note 3
Isolation Damper
Furnace Press Control Damper
Recirc Damper
Note 1: Indicates new equipment (in red) as part of the CDR project.
Note 2: Indicates removed ductwork.
Note 3: Unit 2 CEMS SCR Outlet Nox, Scrubber Inlet SO2, CO2.
Note 4: Existing CEMS monitoring in combined exhaust ductwork (Nox, SO2, CO2, Flow and PM)

Steven L. Beshear
Governor

Energy and Environment Cabinet
Department for Environmental Protection
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601
www.air.ky.gov

Leonard K. Peters
Secretary

July 24, 2013

Mr. Jerry Purvis, Manager, Environmental Affairs
East Kentucky Power Cooperative
4775 Lexington Road
Winchester, Kentucky 40391

RE:	Permittee Name:	East Kentucky Power Cooperative (EKPC)
	Source Name:	John Sherman Cooper Power Station
	AI/Source ID:	3808

Dear Mr. Purvis:

This letter is in response to your letter dated June 24, 2013, requesting a compliance extension to the federal Mercury and Air Toxic Standards (MATS) requirements for the John Sherman Cooper Power Station located in Pulaski County, Kentucky. After reviewing the request, the Division concludes that the submittal contains sufficient information to make a determination regarding the request for an extension of compliance. Furthermore, the Division grants the compliance extension request for Cooper Unit 1 from April 16, 2015, until April 16, 2016. This compliance extension applies to the requirements established under 40 CFR 63, Subpart UUUUU (MATS).

As noted in your compliance extension request, the Division received a significant permit application to the source's existing title V operating permit on March 25, 2013, for the installation of pollution control equipment necessary to comply with the applicable requirements of 40 CFR 63, Subpart UUUUU. The Division is currently processing the submitted application. In accordance with 40 CFR 63.6(i)(4), the conditions of the extension of compliance, specifically the compliance date, granted through this approval letter will be incorporated into the title V permit upon issuance.

If you have further questions regarding this matter, please contact Sean Alteri at (502) 564-3999, extension 4402.

Sincerely,

E-Signed by John Lyons
VERIFY authenticity with ApproveIt

John S. Lyons
Director

EAST KENTUCKY POWER COOPERATIVE

March 25, 2013

Via Hand Delivery

John Lyons, Director
Kentucky Division for Air Quality
200 Fair Oaks, 1st Floor
Frankfort, Kentucky 40601

RECEIVED
MAR 25 2013
PERMIT REVIEW BRANCH
DIVISION FOR AIR QUALITY

Re: Application for Permit Revision
John Sherman Cooper Power Station, Burnside, Kentucky
Permit No. V-05-082 Revision 2
Unit 1 Control Project

Dear Mr. Lyons:

East Kentucky Power Cooperative, Inc. ("EKPC") owns and operates the John Sherman Cooper Power Station ("Cooper") located in Burnside, Pulaski County, Kentucky. EKPC currently operates the Cooper facility pursuant to Permit No V-05-082 R2, although the Title V permit renewal application is pending. The Draft Renewal Permit (No. V-12-019) went to public notice on October 25, 2012.

Cooper Units 1 and 2 are subject to certain regulatory requirements with future compliance dates. 40 CFR Part 63, Subpart UUUUU, commonly known as the Mercury and Air Toxics Standards (MATS) rule, requires compliance by April 16, 2015, absent an extension granted under Section 112 of the Clean Air Act. On or before April 30, 2017, Units 1 and 2 will be required to meet the Best Available Retrofit Technology (BART) determination for both units contained in the Kentucky Regional Haze State Implementation Plan (KYSIP) approved by EPA in March of 2012. To meet the regulatory requirements EKPC must provide additional control of Unit 1 emissions. EKPC thus submits the enclosed application for revision of the permit for retrofit of Unit 1 to achieve the BART and MATS standards by the required compliance dates.

EKPC looks forward to working with the Division in processing this revision application. If you have any questions regarding the submittal, please contact me.

Regards

Jerry Purvis

Jerry Purvis
Director, Environmental Affairs

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

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

A Touchstone Energy Cooperative

Enclosure

cc: Sean Alteri
Ben Markin
Louis Petrey
Chris Wathen
Charles Leveridge

EAST KENTUCKY POWER COOPERATIVE

AIR PERMIT APPLICATION

COOPER UNIT 1 DUCT REROUTE

EAST KENTUCKY POWER COOPERATIVE, INC.

JOHN SHERMAN COOPER POWER STATION

PREPARED BY:

EAST KENTUCKY POWER COOPERATIVE, INC.

P.O. BOX 707

4785 LEXINGTON ROAD

WINCHESTER, KENTUCKY 40391

MARCH 25, 2013

TABLE OF CONTENTS

APPENDIX

1.0 INTRODUCTION

East Kentucky Power Cooperative, Inc. (EKPC) owns and operates the John Sherman Cooper Power Station (Cooper) located at State Highway 1247 South, Burnside, Pulaski County, Kentucky. Permitted equipment at the facility includes two pulverized coal-fired boilers and ancillary equipment and coal handling operations associated with the boilers. EKPC currently operates the Cooper facility pursuant to Permit No V-05-082 R2, although the Title V permit renewal application is pending. The Draft Renewal Permit (No. V-12-019) went to public notice on October 25, 2012.

Cooper Units 1 and 2 are subject to certain regulatory requirements with future compliance dates. 40 CFR Part 63, Subpart UUUUU, commonly known as the Mercury and Air Toxics Standards (MATS) rule, requires compliance by April 16, 2015, absent an extension granted under Section 112 of the Clean Air Act. On or before April 30, 2017, Units 1 and 2 will be required to meet the Best Available Retrofit Technology (BART) determination for both units contained in the Kentucky Regional Haze State Implementation Plan (KYSIP) approved by EPA in March of 2012. 77 Fed. Reg. 19098.[1]

To meet the regulatory requirements EKPC must provide additional control of Unit 1 emissions. EKPC proposes to combine the Unit 1 exhaust gas with the Unit 2 exhaust gas to utilize the recently completed control train with Dry Flue Gas Desulfurization (DFGD) system and Pulse Jet Fabric Filtration (PJFF) control train to achieve MATS and BART compliance for both Unit 1 and Unit 2. Although the project will result in an over-all significant emissions reduction from Cooper Station, the associated changes in monitoring requirements result in the need to seek a significant revision of the permit pursuant to 401 KAR 52:020, Section 16. Only the changes relating to this revision are addressed herein.

Appendix A contains the forms required by DAQ. Appendix B contains a configuration of the project. Appendix C contains emission calculations. Appendix D contains proposed permit language.[2]

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[1] With respect to PM, Unit 1 is also the subject of a pollution control upgrade analysis (PCUA) which may result in adjusted emission requirements. The PCUA is under review by EPA pursuant to a Consent Decree in the case styled *United States v. East Kentucky Power Cooperative, Inc.*, Civil Action No. 04-34-KSF (E.D. KY)(entered Sept. 24, 2007) (Consent Decree).

[2] For clarity, the current permit, V-05-082 R2, is used for the Appendix D mark-up. No changes made in Draft Permit V-12-019 are included in this proposed language, with the exception of removal of the requirement to place a PM CEMS on Unit 1 since removal of that requirement has been specified by modification of the Consent Decree. Likewise, no changes proposed as a result of public comment on the Draft Permit are reflected in the proposed permit language.

2.0 DESCRIPTION OF PROPOSED PROJECT

2.1 Project Description

Cooper Unit 1 is an existing pulverized coal-fired, dry-bottom, wall-fired boiler equipped with an electrostatic precipitator (ESP) and low NO_X burners. Cooper Unit 2 is an existing pulverized coal-fired, dry-bottom, wall-fired boiler equipped with low NO_X burners, Dry Flue Gas Desulfurization (DFGD) system, Selective Catalytic Reduction (SCR), Pulse Jet Fabric Filter (PJFF)[3] and Fuel Solv Treatment. Pursuant to the current Title V permit, V-05-082 Revision 2, EKPC has installed, and is operating, additional controls on Unit 2 including the DFGD and PJFF. Permit V-05-082 Revision 2 also authorized the construction and operation of EU 09 Pebble Lime and Waste Product Handling System, needed for the operation of the DFGD, and the associated additional haul road traffic (EU 10). Continuous emission monitoring systems (CEMS) have also been installed. Cooper Units 1 and 2 share a common stack.

EKPC is proposing to combine the Unit 1 exhaust gas with the Unit 2 exhaust gas to utilize the DFGD/PJFF on Unit 2 to achieve MATS and BART compliance on Unit 1. The MATS/BART compliance option consists of combining the exhaust gas from the Unit 1 induced draft (ID) fan with the Unit 2 exhaust gas prior to the DFGD. Implementation of the Project will result in the DFGD/PJFF, the existing Unit 2 ID fan, and the DFGD/PJFF minimum flow recirculation damper being common components to Unit 1 and Unit 2.

Cooper Unit 1 will be equipped with new ductwork from the Unit 1 ID fan to the Unit 2 ductwork tie-in location, exhaust gas regulating and isolation dampers, integration of the controls systems, and new CEMS equipment. See Section 2.3 below. The DFGD/PJFF equipment will incorporate a modified hydrated lime feed system, including modifications to allow dual hydrator operation. Also, longer fabric filter bags and cages have been recommended if necessary to support the increased gas flow through the DFGD/PJFF equipment.

As it relates to this project, the existing Title V permit identifies an ESP at Unit 1 and provides for two lime hydrators (EU 09-06) and a hydrated lime silo (EU 09-07). The existing Unit 1 ESP will continue to be used for Unit 1 emissions. Pebble lime will continue to be delivered to the Cooper site by truck. The existing pebble lime silo and hydration trains will be utilized as part of the Project. Design modifications will be made to the hydrated lime feed system to allow dual hydrator operation. Truck traffic associated with deliveries of pebble lime and waste ash removal are not expected to increase above the design basis values used for determining the fugitive dust emissions currently in the permit. The hydrated lime system will be upgraded to allow for the simultaneous operation of both hydrator trains.

The Cooper 2 DFGD/PJFF is capable of successfully controlling SO_2, Particulate Matter and Mercury to achieve MATS and BART compliance because of the robust nature of the CDS system design and the performance that it is currently achieving. Some upgrades will be made to the DFGD/PJFF system design to ensure that all necessary performance measures are met.

The DFGD/PJFF was designed to achieve a 30-day rolling average SO_2 limit of 95% removal efficiency or 0.100 lb/MMBtu established by the Consent Decree for Unit 2. The DFGD is

[3] The PJFF has replaced the Unit 2 ESP, which is no longer being used.

currently meeting a removal efficiency of 95% or achieving SO_2 emissions from Unit 2 of 0.100 lb/MMBtu. The above-mentioned modifications allow for simultaneous operation of both hydrator trains, and as a result will increase the maximum operating rate of the hydrated lime silo (EU 09-07) from 25 tons per hour to 50 tons per hour. The additional pebble lime, coupled with the performance quality being achieved by the DFGD show that the system is adequate to control SO_2 from Unit 1 (which is half the size of Unit 2) as well as SO_2 from Unit 2.

Currently the DFGD/PJFF is operating such that PM emissions from Unit 2 are approximately one order of magnitude below the BART SIP PM limit of 0.030 lb/MMBtu. Therefore the DFGD/PJFF has demonstrated capacity to accept and adequately treat the additional gas flow from Unit 1 which will have already been subjected to control through the existing Unit 1 electrostatic precipitator. Longer bags may be utilized in the PJFF portion of the system, resulting in improved control if necessary.

A Project Equipment Configuration is provided at Appendix B.

2.2 Emissions Evaluation

Emissions calculations for Cooper Unit 1 and Emission Unit 09 are provided in Appendix C. Emission Unit 09 will continue to meet existing permit limits. Cooper Unit 1 will see a decrease in emissions of PM and SO_2.[4] Other than the decreases associated with Unit 1 and the increase associated with the increased capacity of the Hydrated Lime Silo, EU 09(07), no other Cooper emission units are expected to experience any change in emissions. Table 1 contains a summary of emissions for the project. Detailed calculations are included in Appendix C.

[4] While there will be a beneficial decrease in SO_2 emissions, SO_2 is not addressed here since PM is the pollutant of concern for BART compliance for purposes of this application.

Table 1
Summary of Project Emissions

Pollutant	Emission Unit	Projected Actual Emissions, tons/year[1]	Baseline Actual Emissions, tons/year	Change in Emissions, tons/year
PM (filterable)	Unit 1	141.9	299.6	-157.7
	Pebble Lime System and Haul Roads	14.6	13.0[2]	1.6
	Total	156.5	312.6	-156.1
PM (total)	Unit 1	212.9	564.6	-351.7
	Pebble Lime System and Haul Roads	14.6	13.0[2]	1.6
	Total	227.5	577.6	-350.1
PM_{10}	Unit 1	130.5	200.8	-70.3
	Pebble Lime System and Haul Roads	13.3	11.7[2]	1.6
	Total	143.8	212.5	-68.7
$PM_{2.5}$	Unit 1	146.3	351.9	-205.6
	Pebble Lime System and Haul Roads	13.1	11.5[2]	1.6
	Total	159.4	363.4	-204.0

[1]Projected future actual emissions conservatively assuming 100 % utilization at 1,080 mmBtu/hr. See Appendix C for emission calculations.

[2]Since these emission units have been in operation for less than one year, baseline actual emissions were set equal to the current potential/allowable emissions for these units. See Appendix C for a summary of current and proposed emissions for these units.

2.3 Continuous Emission Monitoring Systems

Combination of the flue gas from Cooper 1 and 2 and the associated ductwork construction proposed by EKPC will also require modifications to the existing CEMS configuration. The proposed revised approach is explained here. EKPC and EPA are engaging in discussions concerning the monitoring changes that could impact compliance by Unit 1 and 2 with Consent Decree requirements. EKPC will keep the Division advised of the outcome of those discussions.

The proposed tie-in location for flue gas from Cooper Unit 1 will eliminate the existing CEMS location used to measure Cooper Unit 2 inlet SO_2 emissions. This CEMS provides data necessary for demonstrating the compliance of Cooper Unit 2 with emissions limitations pursuant to the Consent Decree and permit which are not applicable to Cooper Unit 1.

The Consent Decree and permit require Cooper Unit 2 to meet a NO_X emissions limit and achieve an SO_2 removal efficiency of 95%. Neither standard is applicable to Cooper Unit 1. To measure controlled Cooper Unit 2 NO_X emissions as well as DFGD inlet SO_2 concentrations, a new CEMS location will be downstream of the Cooper Unit 2 SCR and upstream of the proposed Cooper Unit 1 tie-in location and will consist of NO_X, SO_2 and CO_2 analyzers. The exact CEMS location will satisfy the requirements set forth in 40 CFR Part 60, Appendix A, Method 1. With this system, EKPC will measure Cooper Unit 2 controlled NO_X prior to introduction of Cooper Unit 1 flue gas, upstream from its current location. The system will also measure Cooper 2 inlet SO_2 that will be used to calculate Cooper Unit 2 SO_2 efficiency. NO_X and SO_2 emission concentrations will be converted to lb/10^6 MMBtu units using the measured CO_2 concentration with EPA's F-factor equation which has the following form:

$$E = C \times F_c \times \frac{100}{CO_2}$$

Where
E = SO_2 or NO_X emissions, lb/10^6 MMBtu
C = SO_2 or NO_X concentrations, parts per million (ppm)
F_C = Carbon-based F-factor (bituminous coal is 1,800 scf CO2/10^6 MMBtu)
CO_2 = carbon dioxide concentration, percent

The Cooper Unit 2 SO_2 removal efficiency will be calculated by using the relocated Cooper Unit 2 inlet CEMS in conjunction with a combined Cooper Units 1 and 2 outlet SO_2 measurement. EKPC's proposal will in essence achieve a 95% SO_2 reduction for both units combined even though the SO_2 removal efficiency requirements apply only to Cooper Unit 2.

As already specified in the permit, EKPC will certify and use the relocated CEMS in accordance with the procedures specified in 40 CFR Part 75.

Cooper Unit 2 is presently equipped with a PM CEMS to monitor filterable PM emissions. The PM CEMS is installed to satisfy Consent Decree PM monitoring requirements, although the PM CEMS is not the measure of compliance for the Consent Decree or Title V PM emissions limitations. The PM CEMS is currently located after the PJFF and is not proposed to be relocated. With the proposed change in flue gas stream, the PM CEMS will measure PM for Unit 1 and 2. EKPC is also engaging EPA for discussion of this proposed change.[5]

[5]EKPC notes that discussions with EPA may result in revisions to the Consent Decree monitoring or other requirements. EKPC will supplement this application should revisions be necessary.

3.0 REGULATORY REQUIREMENTS

3.1 Prevention of Significant Deterioration

PSD regulations apply to any new major stationary source or major modification to an existing major source located within an air quality attainment area. Pursuant to 401 KAR 51:017, a project at an existing major stationary source is a major modification for PSD purposes if the project would result in a significant net emissions increase of any NSR regulated pollutant. *Id.* at Section 1(4). The PSD modification significance thresholds are specified in 401 KAR 51:001, Section 1(218). Although the increased utilization of the existing hydrated lime system and dual operation of the existing hydrators result in estimated increases in PM emissions from EU 09 and EU 10, the increased utilization is directly tied to the operation of the DFGD/PJFF to reduce emissions from Cooper Unit 1. Thus, the projected emission increases/decreases are all connected to the proposed Unit 1 control project. Detailed emission calculations, including baseline actual emission calculations for 2008 – 2012 for Unit 1, are presented in Appendix C. As Table 1 above shows, emissions of PM will decrease as a result of this project.

Other than the decreases associated with Unit 1 and the increase associated with the increased capacity of the Hydrated Lime Silo, EU 09(07) (see emission calculations at Appendix C), no other Cooper emission units are expected to experience any change in potential emissions. Therefore, the PSD requirements of 401 KAR 51:017 do not apply.

3.2 BART SIP

Cooper Unit 1 and Unit 2 are subject to BART. On May 28, 2010 the Division submitted to EPA the Regional Haze State Implementation Plan for Kentucky's Class I Area as amended (Kentucky BART Plan) that requires DFGD and Fabric Filtration (FF) as the selected technology for Unit 1 and 2. The SIP establishes an associated filterable particulate matter (PM) emissions limit of 0.030 lb/MMBtu for both units. The Kentucky BART Plan utilizes an emissions limit of 0.030 lb/MMBtu as the limit to demonstrate modeled visibility improvement. These determinations were approved by EPA in March of 2012. 77 Fed. Reg. at 19098. The compliance date for BART is April 30, 2017.

EKPC has installed and is operating DFGD/PJFF on Unit 2. This project will route the exhaust gas from Unit 1 through the Unit 2 DFGD/PJFF. After completion, the selected technology of DFGD/PJFF will have been applied to both units, and both units will comply with the PM emissions limit of 0.030 lb/MMBtu. There will be no change to the common stack parameters as a result of this proposal.

EKPC must comply with the BART SIP requirements on or before April 30, 2017. During the public comment period for Draft Renewal Permit V-12-019, the Division received requests from a third party for inclusion of BART requirements in the renewal permit. At that time, EKPC responded that inclusion of a requirement with a future compliance date would be inappropriate. However, this revision request is the result of EKPC's evaluation of its compliance options for meeting the requirements in the Kentucky BART SIP. Therefore, in the draft language provided at Appendix D, EKPC has included BART SIP requirements.

3.3 Mercury Air Toxics Standards

40 CFR Part 63, Subpart UUUUU, the National Emissions Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units commonly known as the Mercury and Air Toxics Standards (MATS) rule, has a future compliance date of April 16, 2015, unless an extension is granted pursuant to Section 112(i)(3) of the Clean Air Act. EKPC intends to request such an extension in order to complete the work necessary for Unit 1 to be compliant with MATS.

EKPC notes that during the public comment period on Draft Renewal Permit V-12-019, EKPC requested that conditions based on MATS not be included in the revised permit because of substantial uncertainty about the requirements due to ongoing petitions for reconsideration as well as active litigation in the U.S. Court of Appeals for the D.C. Circuit. However, this application is the result of EKPC's evaluation of its compliance options for meeting the MATS requirements. Therefore, in the draft language provided at Appendix D, EKPC has included MATS requirements for each unit (as in the Draft Renewal Permit); however; EKPC retains its request that the Division incorporate the requirements by reference in Section I of the permit for simplicity to ease the burden on the permittee in the event that legal action or EPA reconsideration results in either changes to the promulgated rule or the date of its effectiveness. In addition, EKPC requests that the compliance date be identified as "April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later."

3.4 Compliance Assurance Monitoring

After completion of the Unit 1 retrofit, EKPC expects to use opacity from the common stack as the indicator of compliance for both Units 1 and 2. EKPC proposes to establish the opacity indicator range by conducting testing pursuant to 40 CFR 64.4(c)(1) within 180 days after completion of the initial compliance demonstration performed after project completion. An updated CAM plan would be submitted for the Division's review and approval 180 days thereafter. EKPC will then comply with the approved CAM plan. EKPC has proposed permit language for this CAM approach at Appendix D.

4.0 CONCLUSION

EKPC submits this permit revision request in accordance with 401 KAR 52:020 Section 16(2). Only the changes relating to this revision are addressed herein.

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A

APPENDIX A

PROJECT PERMIT APPLICATION FORMS

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601
(502) 564-3999
http://www.air.ky.gov/

DEP7007AI
Administrative Information
Enter if known AFS Plant ID# 21-199-00005
Agency Use Only
Date Received
Log#
Permit#

PERMIT APPLICATION

The completion of this form is required under Regulations 401 KAR 52:020, 52:030, and 52:040 pursuant to KRS 224. Applications are incomplete unless accompanied by copies of all plans, specifications, and drawings requested herein. Failure to supply information required or deemed necessary by the division to enable it to act upon the application shall result in denial of the permit and ensuing administrative and legal action. Applications shall be submitted in triplicate.

1) APPLICATION INFORMATION

Note: The applicant must be the owner or operator. (The owner/operator may be individual(s) or a corporation.)

Name: East Kentucky Power Cooperative, Inc.

Title: ____________ Phone: ____________
(If applicant is an individual)

Mailing Address: Company East Kentucky Power Cooperative, Inc.

Street or P.O. Box: 4775 Lexington Road, PO Box 707

City: Winchester State: KY Zip Code: 40392-0707

Is the applicant (check one): ☐ Owner ☐ Operator ☐ Owner & Operator ☒ Corporation/LLC* ☐ LP**

* If the applicant is a Corporation or a Limited Liability Corporation, submit a copy of the current Certificate of Authority from the Kentucky Secretary of State. – ON FILE AT KDAQ

** If the applicant is a Limited Partnership, submit a copy of the current Certificate of Limited Partnership from the Kentucky Secretary of State.

Person to contact for technical information relating to application:

Name: Jerry Purvis

Title: Director of Environmental Affairs Phone: 859-744-9244

2) OPERATOR INFORMATION

Note: The applicant must be the owner or operator. (The owner/operator may be individual(s) or a corporation.)

Name: East Kentucky Power Cooperative, Inc.

Title: ____________ Phone: 859-744-4812

Mailing Address: Company East Kentucky Power Cooperative, Inc.

Street or P.O. Box: 4775 Lexington Road, PO Box 707

City: Winchester State: KY Zip Code: 40392-0707

DEP7007AI
(Continued)

3) TYPE OF PERMIT APPLICATION

For new sources that currently *do not* hold *any* air quality permits in Kentucky and are required to obtain a permit prior to construction pursuant to 401 KAR 52:020, 52:030, or 52:040.

☐ Initial Operating Permit (the permit will authorize both construction and operation of the new source)

Type of Source (*Check all that apply*): ☐ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

For existing sources that do not have a source-wide Operating Permit required by 401 KAR 52:020, 52:030, or 52:040.

Type of Source (*Check all that apply*): ☐ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

(*Check one only)*

☐ Initial Source-wide Operating Permit ☐ Modification of Existing Facilities at Existing Plant

☐ Construction of New Facilities at Existing Plant

☐ Other (explain) ______

For existing sources that currently have a source-wide Operating Permit.

Type of Source (*Check all that apply*): ☒ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

Current Operating Permit # V-05-082 R2

☐ **Administrative Revision** (describe type of revision requested, e.g. name change): ______

☐ **Permit Renewal** ☒ **Significant Revision** ☐ **Minor Revision**

☐ Addition of New Facilities ☐ Modification of Existing Facilities

For all construction and modification requiring a permit pursuant to 401 KAR 52:020, 52:030, or 52:040.

Proposed Date for Start of Construction or Modification: May, 2014

Proposed date for Operation Start-up: April, 2016

4) SOURCE INFORMATION

Source Name: **John Sherman Cooper Power Station**

Source Street Address: **State Highway 1247 South**

City: **Burnside** **Zip Code:** **KY** **County:** **Pulaski**

Primary Standard Industrial Classification (SIC) Category: **Electric Power Generation** **Primary SIC #:** **4911**

Property Area (Acres or Square Feet): **860 acres** **Number of Employees:** **76**

Description of Area Surrounding Source (*check one*):
☐ Commercial Area ☐ Residential Area ☐ Industrial Area ☐ Industrial Park ☒ Rural Area ☐ Urban Area

Approximate Distance to Nearest Residence or Commercial Property: **2,000 feet**

UTM or Standard Location Coordinates: (*Include topographical map showing property boundaries*)

UTM Coordinates: Zone 16 Horizontal (km) 714.2 Vertical (km) 4097.2

Standard Coordinates: Latitude 37 Degrees 00 Minutes 00 Seconds

Longitude 84 Degrees 35 Minutes 30 Seconds

DEP7007AI
(Continued)

4)	SOURCE INFROMATION (CONTINUED)

Is any part of the source located on federal land? ☐ Yes ☒ No

What other environmental permits or registrations does this source currently hold in Kentucky?

Landfill Permit Special Waste Landfill Permit

KPDES Permit

Hazardous Waste Registration

What other environmental permits or registrations does this source need to obtain in Kentucky?

None

5)	OTHER REQUIRED INFORMATION

Indicate the type(s) and number of forms attached as part of this application.

3	DEP7007A	Indirect Heat Exchanger, Turbine, Internal Combustion Engine	___	DEP7007R	Emission Reduction Credit
2	DEP7007B	Manufacturing or Processing Operations	___	DEP7007S	Service Stations
___	DEP7007C	Incinerators & Waste Burners	___	DEP7007T	Metal Plating & Surface Treatment Operations
___	DEP7007F	Episode Standby Plan	5	DEP7007V	Applicable Requirements & Compliance Activities
___	DEP7007J	Volatile Liquid Storage	___	DEP7007Y	Good Engineering Practice (GEP) Stack Height Determination
___	DEP7007K	Surface Coating or Printing Operations	___	DEP7007AA	Compliance Schedule for Noncomplying Emission Units
___	DEP7007L	Concrete, Asphalt, Coal, Aggregate, Feed, Corn, Flour, Grain, & Fertilizer	___	DEP7007BB	Certified Progress Report
___	DEP7007M	Metal Cleaning Degreasers	___	DEP7007CC	Compliance Certification
5	DEP7007N	Emissions, Stacks, and Controls Information	___	DEP7007DD	Insignificant Activities
___	DEP7007P	Perchloroethylene Dry Cleaning Systems			

Check other attachments that are part of this application.

Required Data		Supplemental Data	
☐	Map or Drawing Showing Location	☐	Stack Test Report
☐	Process Flow Diagram and Description	☐	Certificate of Authority from the Secretary of State (for Corporations and Limited Liability Companies)
☐	Site Plan Showing Stack Data and Locations	☐	Certificate of Limited Partnership from the Secretary of State (for Limited Partnerships)
☒	Emission Calculation Sheets	☐	Claim of Confidentiality (See 400 KAR 1:060)
☐	Material Safety Data Sheets (MSDS)	☐	Other (Specify) ____________

Indicate if you expect to emit, in any amount, hazardous or toxic materials or compounds or such materials into the atmosphere from any operation or process at this location.

☐ Pollutants regulated under 401 KAR 57:002 (NESHAP) ☒ Pollutants listed in 401 KAR 63:060 (HAPS)

☐ Pollutants listed in 40 CFR 68 Subpart F [112(r) pollutants] ☐ Other

Has your company filed an emergency response plan with local and/or state and federal officials outlining the measures that would be implemented to mitigate an emergency release?

☒ Yes ☐ No

Check whether your company is seeking coverage under a permit shield. If "Yes" is checked, applicable requirements must be identified on Form DEP7007V. Identify any non-applicable requirements for which you are seeking permit shield coverage on a separate attachment to the application.

☒ Yes ☐ No ☐ **A list of non-applicable requirements is attached**

*** - No change to non-applicable requirements since last permit revision**

DEP7007AI
(Continued)

6)	OWNER INFORMATION

Note: If the applicant is the owner, write "same as applicant" on the name line.

Name: Same as Applicant

Title: ______ **Phone:** ______

Mailing Address:
Company ______

Street or P.O. Box: 4775 Lexington Road

City: Winchester **State:** KY **Zip Code:** 40392-0707

List names of owners and officers of your company who have an interest in the company of 5% or more.

Name	Position (owner, partner, president, CEO, treasurer, etc.)
None	

(attach another sheet if necessary)

7)	SIGNATURE BLOCK

I, the undersigned, hereby certify under penalty of law, that I am a responsible official, and that I have personally examined, and am familiar with, the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

BY: Jerry Purvis
(Authorized Signature)

3/25/13
(Date)

Jerry Purvis **Director of Environmental Affairs**

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 01
Emission Unit # 01

1) Type of Unit (Make, Model, Etc.): Babcock and Wilcox

Date Installed: 1965 Cost of Unit: $25.7 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Unit 1

2a) Kind of Unit (Check one):
1. Indirect Heat Exchanger X
2. Gas Turbine for Electricity Generation ____
3. Pipe Line Compressor Engines:
   ____ Gas Turbine
   ____ Reciprocating engines
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. Industrial Engine ____

2b) Rated Capacity: (Refer to manufacturer's specifications)
1. Fuel input (mmBTU/hr): 1080
2. Power output (hp): ____
   Power output (MW): ____

SECTION 1. FUEL

3) Type of Primary Fuel (*Check*):

X A. Coal ____ B. Fuel Oil # *(Check one)* ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ C. Natural Gas ____ D. Propane ____ E. Butane ____ F. Wood ____ G. Gasoline

____ H. Diesel ____ I. Other (*specify*) ____

4) Secondary Fuel (*if any, specify type*): #2 Fuel Oil; up to 3% wood waste of total fuel blend in tons

5) Fuel Composition

Type	Percent Ash[a] Maximum	Percent Sulfur[b] Maximum	Heat Content Corresponding to:[c,d] Maximum Ash	Maximum Sulfur
Primary (Coal)	8% - 15%	Typically 1.5% - 4%	11,000 – 13,000	11,000 – 13,000
Secondary (Wood Waste)	Not available	Not available	5,000 – 7,000	5,000 – 7,000
Secondary (Fuel Oil)	0.01	0.50	140,000	140,000

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) Maximum Annual Fuel Usage Rate (*please specify units*)*:

7) Fuel Source or supplier: Appalachian coal fields

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

**DEP7007A
(Continued)**

8) **MAXIMUM OPERATING SCHEDULE FOR THIS UNIT***

24 hours/day 7 days/week 365 weeks/year

9) **If this unit is multipurpose, describe percent in each use category:**

Space Heat ________% Process Heat ___________ % Power _________ %

10) **Control options for turbine/IC engine (*Check*)**

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) ____________________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) **Coal-Fired Units**

X Pulverized Coal Fired:

X Dry Bottom X Wall Fired
__ Wet Bottom __ Tangentially Fired

Fly Ash Rejection:

☐ Yes ☐ No

________ Cyclone Furnace
________ Spreader Stoker
________ Overfeed Stoker
________ Underfeed Stoker
________ Fluidized Bed Combustor:
  ______ Circulating Bed
  ______ Bubbling Bed
________ Hand-fed
________ Other (*specify*) ____________________

12) **Oil-Fired Unit**

______ Tangentially (Corner) Fired ______ Horizontally Opposed (Normal) Fired

13) **Wood-Fired Unit**

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven ______ Stoker ______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) **Natural Gas-Fired Units**

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

**DEP7007A
(Continued)**

15) **Combustion Air** **Draft:** ______ Natural __X__ Induced – Balanced Draft Boiler

Forced Pressure ________ lbs/sq. in.

Percent excess air (air supplied in excess of theoretical air) __30__ %

SECTION III

16) **Additional Stack Data**

A. Are sampling ports provided? X Yes ☐ No
B. If yes, are they located in accordance with 40 CFR 60*? X Yes ☐ No
C. List other units vented to this stack __Unit 2__

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Primary fuel and secondary fuel are delivered to the site via truck and stored in storage piles. Dust control measures include wet suppression and fabric filtration for ash storage bins.

Ash Disposal – fly ash and bottom ash are collected dry and transported to the permitted landfill. Fugitive dust emissions are controlled by a dust suppression system.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007B
MANUFACTURING OR PROCESSING OPERATIONS

(Please read instructions before completing this form)

Emission Point # (1)	Process Description (2)	Continuous or Batch (3)	Maximum Operating Schedule (Hours/Day, Days/Week, Weeks/Year (4)	Process Equipment (Make, Model, Etc.) (5)	Date Installed (6)
09(07)	Hydrated Lime Silo	C	24/7/52	Hydrated Lime Silo	2011

Emission Point # (1)	List Raw Material(s) Used (7)	Maximum Quantity Input Of Each Raw Material (Specify Units/Hour) (8) See Item 18	Type of Products (9) See Item 18	Quantity Output* (Specify Units)	
				Maximum Hourly Rated Capacity (Specify Units) (10a)	Maximum Annual (Specify Units) (10b)
09(07)	Hydrated Lime	50 tons/hour	Hydrated lime	50 tons/hour	

*(10a) Rated Capacity of Equipment (10b) Should be entered only if applicant requests operating restrictions through federally enforceable limitations

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DEP7007B (Continued)

IMPORTANT: Form DEP7007N, Emission, Stacks, and Controls Information must be completed for each emission unit listed below.

Emission Point # (1)	Fuel Type for Process Heat (11)	Rated Burner Capacity (BTU/Hour) (12)	Fuel Composition		Fuel Usage Rates		Note:
			% Sulfur (13a)	% Ash (13b)	Maximum Hourly (14a)	Maximum Annual* (14b)	If the combustion products are emitted along with the process emissions, indicate so in this column by writing "combined." (15)
NA							

16) Make a complete list of all wastes generated by each process (e.g. wastewater, scrap, rejects, cleanup waste, etc.). List the hourly (or daily) and annual quantities of each waste and the method of final disposal. (Use a separate sheet of paper, if necessary)

17) IMPORTANT: Submit a process flow diagram. Label all materials, equipment and emission point numbers. *** See Appendix B ***

18) Material Safety Data Sheets with complete chemical compositions are required for each process. *** Not applicable ***

*(14b) Should be entered only if applicant requests operating restrictions through federally enforceable permit conditions.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007N

Emissions, Stacks, and Controls Information

Applicant Name: East Kentucky Power Cooperative, Inc. Log # ______

SECTION I. Emissions Unit and Emission Point Information

KyEIS ID #	Emissions Unit and Emission Point Descriptions		Maximum Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Maximum Operating Parameters: Annual Operating Hours (hrs/yr)	Permitted Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Permitted Operating Parameters: Annual Operating Rate (SCC Units/yr)	Permitted Operating Parameters: Annual Operating Hours (hrs/yr)
001	Emission Unit Name:	**Unit 1 Indirect Heat Exchanger**		8,760			
	Date Constructed:	1965					
	HAPs present?	☑ Yes ☐ No					
01	Emission Point Name:	**Unit 1 Indirect Heat Exchanger**	45	8,760			
	Source ID:	Unit 01					
	SCC Code:	10100202					
	SCC Units:	Tons Burned					
	KyEIS Stack #:	0002					
	Fuel Ash Content:	Up to 15%					
	Fuel Sulfur Content:	4.2%					
	Fuel Heat Content Ratio:	12000 Btu/lb					
	Applicable Regulations	401 KAR 61:015, 401 KAR 51:160, 401 KAR 51:210, 401 KAR 51:220, 401 KAR 51:230, 401 KAR 52:060, 40 CFR 51 Subpart P (BART), 40 CFR 63 Subpart UUUUU 40 CFR Part 64, 40 CFR Part 75					

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DEP7007N
(continued)

SECTION I. Emission Units and Emission Point Information (continued)											
KyEIS ID #	Emission Factors			Control Equipment		Hourly (lb/hr) Emissions[1]			Annual (tons/yr) Emissions		
	Pollutant	Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equipment Association	Pollutant Overall Efficiency (%)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
001											
01	PM	90.00	0.030 lb/mmBtu	1st control device ESP/Baghouse KyEIS Control ID #: Collection efficiency:	99.2%	4050.0	32.40		17739.0	141.9	
				2nd control device KyEIS Control ID #: Collection efficiency:							
				3rd control device KyEIS Control ID #:							

[1] Emissions based upon the maximum annual emissions calculated using a heat input rate of 1080 lb/mmBtu and assuming 8760 hours of operation. Maximum hourly emissions were modeled using a short term heat input rate of 1350 mmBtu/hr in the March 18, 2009 BART submittal.

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Commonwealth of Kentucky
Energy and Environment Cabinet
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DIVISION FOR AIR QUALITY

DEP7007N

Emissions, Stacks, and Controls Information

Applicant Name: East Kentucky Power Cooperative, Inc. Log # ______

SECTION I. Emissions Unit and Emission Point Information

KyEIS ID #	Emissions Unit and Emission Point Descriptions		Maximum Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Maximum Operating Parameters: Annual Operating Hours (hrs/yr)	Permitted Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Permitted Operating Parameters: Annual Operating Rate (SCC Units/yr)	Permitted Operating Parameters: Annual Operating Hours (hrs/yr)
009	Emission Unit Name:	**Pebble Lime & Waste Product System**		8,760			
	Date Constructed:						
	HAPs present?	☐ Yes ☑ No					
07	Emission Point Name:	**Hydrated Lime Silo**	50	8,760			
	Source ID:	07					
	SCC Code:	39999999					
	SCC Units:	Tons Processed					
	KyEIS Stack #:	09(07)					
	Fuel Ash Content:						
	Fuel Sulfur Content:						
	Fuel Heat Content Ratio:						
	Applicable Regulations:	401 KAR 59:010, 40 CFR 64					
	Emission Point Name:						
	Source ID:						
	SCC Code:						
	SCC Units:						
	KyEIS Stack #:						
	Fuel Ash Content:						
	Fuel Sulfur Content:						
	Fuel Heat Content Ratio:						
	Applicable Regulations:						

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DEP7007N
(continued)

SECTION I. Emission Units and Emission Point Information (continued)											
KyEIS ID #	Emission Factors			Control Equipment		Hourly (lb/hr) Emissions[1]			Annual (tons/yr) Emissions		
	Pollutant	Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equipment Association	Pollutant Overall Efficiency (%)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
009 07	PM$_{10}$	1.3000	Grain Loading of 0.005 gr/dscf 99.0% control	<u>1st control device</u> KyEIS Control ID #: Collection efficiency: <u>2nd control device</u> KyEIS Control ID #: Collection efficiency:	Baghouse 99.000% (estimated)	65.00	0.650	32.37	284.70	2.85	
				<u>**1st control device**</u> **KyEIS Control ID #:** **Collection efficiency:** <u>**2nd control device**</u> **KyEIS Control ID #:** **Collection efficiency:**							

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(continued)

SECTION II. Stack Information										
KyEIS Stack ID #	Stack Description	Stack Physical Data			Stack Geographic Data			Stack Gas Stream Data		
		Height (ft)	Diameter (ft)	Vent Height (ft)	Vertical Coordinate	Horizontal Coordinate	Coordinate Collection Method Code	Flowrate (acfm)	Temperature (°F)	Exit Velocity (ft/sec)
01	Unit 1 Indirect Heat Exchanger	260	18		4097212	714228	DRG	320000	170.00	69
09(07)	Hydrated Lime Silo	160	1.33		4097113	714339	DRG	16345	77.00	196

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Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance Activities

APPLICANT NAME: East Kentucky Power Cooperative, Inc.-Cooper Station

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
01	Unit 1	PM	401 KAR 61:015	0.23 lb/mmBtu	Emissions testing
		PM	40 CFR 51, Subpart P (BART)	0.030 lb/mmBtu filterable PM once controls are on-line consistent with the BART demonstration	Emissions testing
		Opacity	401 KAR 61:015	40% based on a six-minute average (60% for one six-minute period during any 60 consecutive minutes/exception for start up)	Method 9
		HAPs	40 CFR 63, Subpart UUUUU	As specified under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
02	Unit 2	PM	401 KAR 61:015	0.23 lb/mmBtu	Emissions testing
		PM	40 CFR 51, Subpart P (BART)	0.030 lb/mmBtu filterable PM consistent with the BART demonstration	Emissions testing
		Opacity	401 KAR 61:015	40% based on a six-minute average (60% for one six-minute period during any 60 consecutive minutes/exception for start up)	Method 9
		HAPs	40 CFR 63, Subpart UUUUU	As specified under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
09(07)	Hydrated Lime Silo	PM, opacity	401 KAR 59:010	Opacity shall not exceed 20%. PM shall not exceed 32.37 lb/hour.	Visual observations, proper fabric filter operation.

DEP7007V
continued

APPLICANT NAME: East Kentucky Power Cooperative, Inc.-Cooper Station

SECTION II. MONITORING REQUIREMENTS

KYEIS No.[1]	Emission Unit Description[2]	Contaminant[3]	Origin of Requirement or Standard[4]	Parameter Monitored[7]	Description of Monitoring[8]
01	Unit 1	PM	401 KAR 61:015	n/a	n/a
		PM	40 CFR 51, Subpart P (BART)	n/a	n/a
		Opacity	401 KAR 61:015, 401 KAR 61:005	Opacity	Continuous monitoring
		CO2/Flow	401 KAR 61:005, 40 CFR 75	CO_2/Flow	Continuous monitoring
		HAPs	40 CFR 63, Subpart UUUUU	Applicable monitoring under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by Apri 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
02	Unit 2	PM	401 KAR 61:015	n/a	n/a
		PM	40 CFR 51, Subpart P (BART)	n/a	n/a
		Opacity	401 KAR 61:015, 401 KAR 61:005	Opacity	Continuous monitoring
		CO2/Flow	401 KAR 61:005, 40 CFR 75	CO_2/Flow	Continuous monitoring
		HAPs	40 CFR 63, Subpart UUUUU	Applicable monitoring under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by Apri 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
09(07)	Hydrated Lime Silo	PM, opacity	40 CFR 64 (CAM)	Visual emissions	Qualitative visual emission observations and Method 9 observations.

APPLICANT NAME: East Kentucky Power Cooperative, Inc.-Cooper Station

DEP7007V
continued

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.[1]	Emission Unit Description[2]	Contaminant[3]	Origin of Requirement or Standard[4]	Parameter Recorded[9]	Description of Recordkeeping[10]
01	Unit 1	PM	401 KAR 61:015	n/a	n/a
		PM	40 CFR 51, Subpart P (BART)	n/a	n/a
		Opacity	401 KAR 61:015, 401 KAR 61:005	Opacity	Keep all records for five years
		CO2/Flow	401 KAR 61:005, 40 CFR 75	CO_2/Flow	Keep all records for five years
		HAPs	40 CFR 63, Subpart UUUUU	Records specified under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
02	Unit 2	PM	401 KAR 61:015	n/a	n/a
		PM	40 CFR 51, Subpart P (BART)	n/a	n/a
		Opacity	401 KAR 61:015, 401 KAR 61:005	Opacity	Keep all records for five years
		CO2/Flow	401 KAR 61:005, 40 CFR 75	CO_2/Flow	Keep all records for five years
		HAPs	40 CFR 63, Subpart UUUUU	Records specified under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
09(07)	Hydrated Lime Silo	PM, opacity	40 CFR 64 (CAM)	Test data	Maintain records of emissions testing, visual observations, and Method 9 data.

DEP7007V
continued

APPLICANT NAME: East Kentucky Power Cooperative, Inc.-Cooper Station

SECTION IV. REPORTING REQUIREMENTS

KYEIS No.[1]	Emission Unit Description[2]	Contaminant[3]	Origin of Requirement or Standard[4]	Parameter Reported[11]	Description of Reporting[12]
01	Unit 1	PM	401 KAR 61:015	PM	Submit quarterly reports
		PM	40 CFR 51, Subpart P (BART)	n/a	n/a
		Opacity	401 KAR 61:005	Opacity	Submit quarterly reports
		HAPs	40 CFR 63, Subpart UUUUU	Parameters specified under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by Apri 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
02	Unit 2	PM	401 KAR 61:015	PM	Submit quarterly reports
		PM	40 CFR 51, Subpart P (BART)	n/a	n/a
		Opacity	401 KAR 61:005	Opacity	Submit quarterly reports
		HAPs	40 CFR 63, Subpart UUUUU	Parameters specified under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by Apri 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
09(07)	Hydrated Lime Silo	PM, opacity	40 CFR 64 (CAM)	Test results	Submit reports of emissions testing and opacity observations.

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continued

APPLICANT NAME: East Kentucky Power Cooperative, Inc.-Cooper Station

SECTION V. TESTING REQUIREMENTS

KYEIS No.[1]	Emission Unit Description[2]	Contaminant[3]	Origin of Requirement or Standard[4]	Parameter Tested[13]	Description of Testing[14]
01	Unit 1	PM	401 KAR 61:015	PM	Initially and within third year of permit
		PM	40 CFR 51, Subpart P (BART)	n/a	
		Opacity	401 KAR 61:005, 401 KAR 50:045	Opacity	Method 9 annually and as required by the Cabinet
		HAPs	40 CFR 63, Subpart UUUUU	Parameters specified under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
02	Unit 2	PM	401 KAR 61:015	PM	Initially and within third year of permit
		PM	40 CFR 51, Subpart P (BART)	n/a	
		Opacity	401 KAR 61:005, 401 KAR 50:045	Opacity	Method 9 annually and as required by the Cabinet
		HAPs	40 CFR 63, Subpart UUUUU	Parameters specified under Subpart UUUUU	The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.
09(07)	Hydrated Lime Silo	PM, opacity	40 CFR 64 (CAM)	Opacity	Method 9 for determination of opacity, if needed

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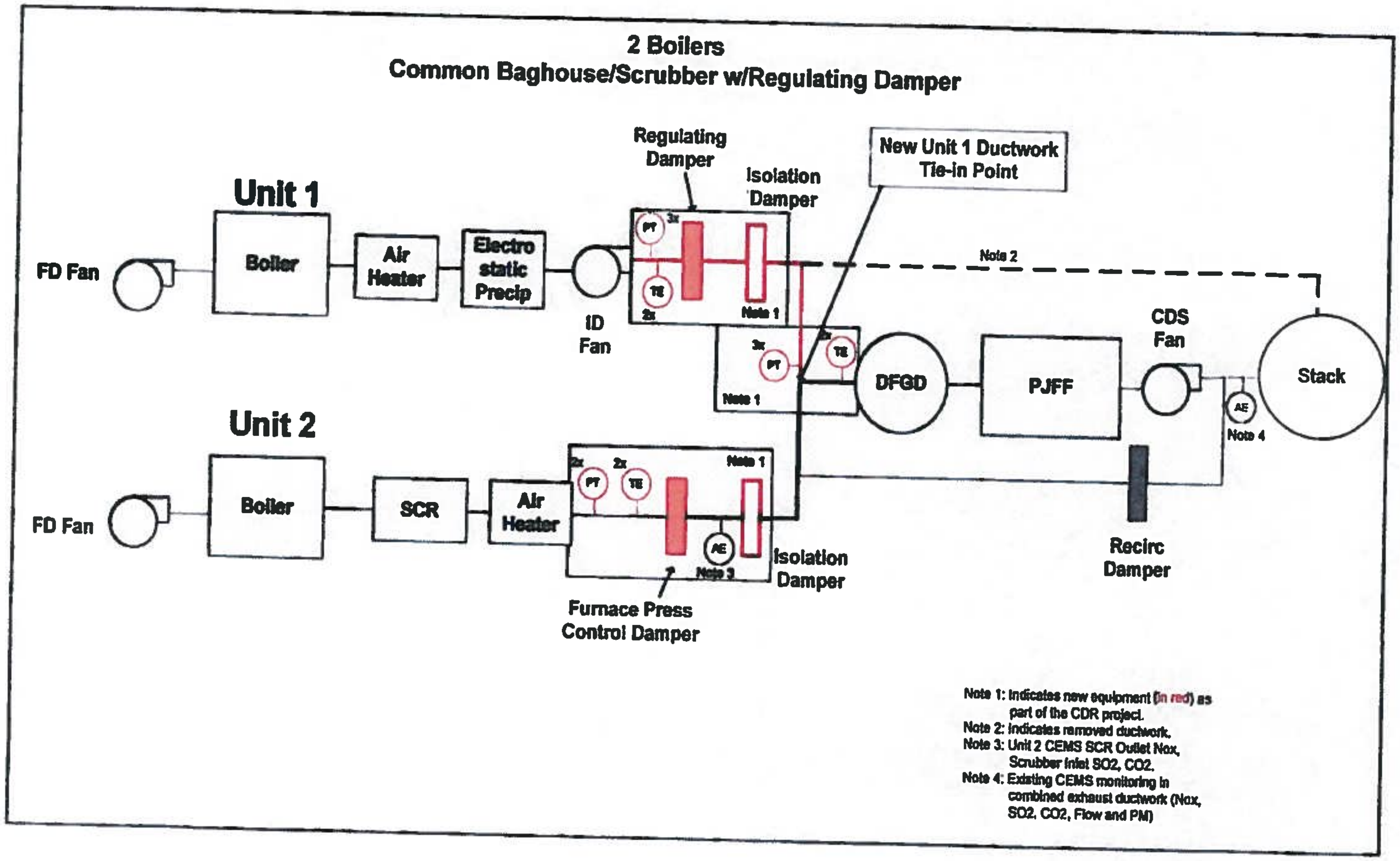
B

APPENDIX B

PROJECT EQUIPMENT CONFIGURATION



2 Boilers
Common Baghouse/Scrubber w/Regulating Damper
Unit 1
FD Fan
Boiler
Air Heater
Electro static Precip
ID Fan
Regulating Damper
Isolation Damper
New Unit 1 Ductwork Tie-in Point
PT
TE
3x
2x
Note 1
Note 2
DFGD
PJFF
CDS Fan
Stack
AE
Note 4
Unit 2
FD Fan
Boiler
SCR
Air Heater
Note 3
Isolation Damper
Furnace Press Control Damper
Recirc Damper
Note 1: Indicates new equipment (in red) as part of the CDR project.
Note 2: Indicates removed ductwork.
Note 3: Unit 2 CEMS SCR Outlet Nox, Scrubber Inlet SO2, CO2.
Note 4: Existing CEMS monitoring in combined exhaust ductwork (Nox, SO2, CO2, Flow and PM)

C

APPENDIX C

EMISSION CALCULATIONS

Cooper Unit 1 Duct Reroute

Emission Calculations

Summary of Project Emissions

Pollutant	Emission Unit	Projected Actual Emissions, tons/year[1]	Baseline Actual Emissions, tons/year	Change in Emissions, tons/year
PM (filterable)	Unit 1	141.9	299.6	-157.7
	Pebble Lime System and Haul Roads	14.6	13.0[2]	1.6
	Total	156.5	312.6	-156.1
PM (total)	Unit 1	212.9	564.6	-351.7
	Pebble Lime System and Haul Roads	14.6	13.0[2]	1.6
	Total	227.5	577.6	-350.1
PM_{10}	Unit 1	130.5	200.8	-70.3
	Pebble Lime System and Haul Roads	13.3	11.7[2]	1.6
	Total	143.8	212.5	-68.7
$PM_{2.5}$	Unit 1	146.3	351.9	-205.6
	Pebble Lime System and Haul Roads	13.1	11.5[2]	1.6
	Total	159.4	363.4	-204.0

[1]Projected future actual emissions conservatively assuming 100 % utilization at 1,080 mmBtu/hr. See calculations below.
[2]Since these emission units have been in operation for less than one year, baseline actual emissions were set equal to the current potential emissions for these units. See calculations below.

Emission Unit 01 – Unit 1 Emissions:

Proposed PM Emissions = 0.030 lb/mmBtu filterable PM, 0.045 lb/mmBtu total PM

Maximum Heat Input (Permit Description) = 1080 mmBtu/hr

Example calculation for filterable PM projected actual emissions (assuming 100% utilization at 1080 mmBtu/hr):

1080 mmBtu/hr x 0.030 lb/mmBtu = 32.4 lb/hr
32.4 lb/hr x 8760 hr/yr x ton/2000 lb = 141.9 tons/yr

Summary of Projected Emissions for Unit 1 After Duct Reroute to DFGD/PJFF Control Train

Pollutant	Emission Factor	Projected Actual Emissions, lb/hr	Projected Actual Emissions, tons/yr
PM, Filterable	0.030 lb/mmBtu[1]	32.4	141.9
PM, Total	0.045 lb/mmBtu[2]	48.6	212.9
PM_{10}	0.0276 lb/mmBtu[3]	29.8	130.5
$PM_{2.5}$	0.0309 lb/mmBtu[4]	33.4	146.3

[1]Proposed limit for MATS and BART compliance.
[2]Based upon the National Parks Service PM speciation spreadsheets consistent with the BART modeling for Cooper Unit 1.
[3]Filterable PM_{10} calculated by applying the percent of PM_{10} listed in AP-42 Table 1.1-6 (92%) for baghouse control to the filterable PM value of 0.030 lb/mmBtu (for emissions inventory purposes).
[4]Calculated as filterable $PM_{2.5}$ plus total condensable emissions, where filterable $PM_{2.5}$ calculated by applying the percent of $PM_{2.5}$ listed in AP-42 Table 1.1-6 for baghouse control (53%) to the filterable PM value of 0.030 lb/mmBtu, then assuming that all of the condensable portion (equivalent to 0.015 lb/mmBtu) is $PM_{2.5}$ (for emissions inventory purposes).

Emission Unit 09 – Pebble Lime and Waste Product Handling System

The only individual source of emissions within this emission unit that will have a change in projected actual emissions due to the Unit 1 Duct Reroute is Emission Unit 09(07), the Hydrated Lime Silo, due to doubling the throughput rate and flow rate to accommodate the system running for Unit 1 control. Projected actual emissions for this unit are calculated as follows:

Projected maximum flow rate = 15,218 dscfm
Maximum PM grain loading = 0.005 gr/dscf

PM Emissions = 15,218 dscf/min x 60 min/hr x 0.005 gr/dscf x lb/7000 gr = 0.65 lb/hr
0.65 lb/hr x 8760 hr/yr x ton/2000 lb = 2.85 tons/yr

East Kentucky Power Cooperative, Inc.
Summary of Permit No. V-05-082 R2 Calculated Pollutant Emissions
Pebble Lime System and Paved Haul Road Emissions

EP	Source	Pollutant	Throughput Rate	Units	Throughput Rate	Units	Emission Factor	Units	Ref	Control Efficiency	Uncontrolled Emissions lb/hr	Uncontrolled Emissions tons/yr	Controlled Emissions lb/hr	Controlled Emissions tons/yr
09(01)	New Waste Product Silo #1	$PM/PM_{10}/PM_{2.5}$	40	tons/hr	3163	dscfm	0.005	gr/dscf	1	99.0%	13.56	59.37	0.14	0.6
09(02)	New Waste Product Silo #2	$PM/PM_{10}/PM_{2.5}$	40	tons/hr	3163	dscfm	0.005	gr/dscf	1	99.0%	13.56	59.37	0.14	0.6
09(03)	Vacuum System #1	$PM/PM_{10}/PM_{2.5}$	40	tons/hr	15217	dscfm	0.005	gr/dscf	1	99.0%	65.22	285.64	0.65	2.9
09(03)	Vacuum System #2	$PM/PM_{10}/PM_{2.5}$	40	tons/hr	15217	dscfm	0.005	gr/dscf	1	99.0%	65.22	285.64	0.65	2.9
09(04)	Pebble Lime Silo	$PM/PM_{10}/PM_{2.5}$	19	tons/hr	7609	dscfm	0.005	gr/dscf	1	99.0%	32.61	142.83	0.33	1.4
09(05)	Hydrator Feed Bin #1	$PM/PM_{10}/PM_{2.5}$	25	tons/hr	1413	dscfm	0.005	gr/dscf	1	99.0%	6.06	26.52	0.06	0.3
09(05)	Hydrator Feed Bin #2	$PM/PM_{10}/PM_{2.5}$	25	tons/hr	1413	dscfm	0.005	gr/dscf	1	99.0%	6.06	26.52	0.06	0.3
09(06)	Lime Hydrator #1	$PM/PM_{10}/PM_{2.5}$	19	tons/hr	2069	dscfm	0.005	gr/dscf	1	99.0%	8.87	38.84	0.09	0.4
09(06)	Lime Hydrator #2	$PM/PM_{10}/PM_{2.5}$	19	tons/hr	2069	dscfm	0.005	gr/dscf	1	99.0%	8.87	38.84	0.09	0.4
09(07)	Hydrated Lime Silo	$PM/PM_{10}/PM_{2.5}$	25	tons/hr	7609	dscfm	0.005	gr/dscf	1	99.0%	32.61	142.83	0.33	1.4
09(08)	Lime Dust Silo	$PM/PM_{10}/PM_{2.5}$	1	tons/hr	1630	dscfm	0.005	gr/dscf	1	99.0%	6.99	30.60	0.07	0.3
10	Paved Roadways	PM			48552.23	miles/year	0.1345	lb/VMT	2	50.0%	0.75	3.27	0.37	1.6
10	Paved Roadways	PM_{10}			48552.23	miles/year	0.0269	lb/VMT	2	50.0%	0.15	0.65	0.07	0.3
10	Paved Roadways	$PM_{2.5}$			48552.23	miles/year	0.0066	lb/VMT	2	50.0%	0.04	0.16	0.02	0.1
	Total	PM												13.0
	Total	PM_{10}												11.7
	Total	$PM_{2.5}$												11.5

1 Expected Filter Performance - PM, PM_{10}, and $PM_{2.5}$ assumed to be equivalent
2 AP-42 Chapter 13.2.1, control of 50%. Hourly rates reflect the average rates over 8760 hours of operation

East Kentucky Power Cooperative, Inc.
Summary of Projected Actual Pollutant Emissions
Pebble Lime System and Paved Haul Road Emissions

EP	Source	Pollutant	Throughput Rate	Units	Throughput Rate	Units	Emission Factor	Units	Ref	Control Efficiency	Uncontrolled Emissions lb/hr	Uncontrolled Emissions tons/yr	Controlled Emissions lb/hr	Controlled Emissions tons/yr
09(01)	New Waste Product Silo #1	$PM/PM_{10}/PM_{2.5}$	40	tons/hr	3163	dscfm	0.005	gr/dscf	1	99.0%	13.56	59.37	0.14	0.6
09(02)	New Waste Product Silo #2	$PM/PM_{10}/PM_{2.5}$	40	tons/hr	3163	dscfm	0.005	gr/dscf	1	99.0%	13.56	59.37	0.14	0.6
09(03)	Vacuum System #1	$PM/PM_{10}/PM_{2.5}$	40	tons/hr	15217	dscfm	0.005	gr/dscf	1	99.0%	65.22	285.64	0.65	2.9
09(03)	Vacuum System #2	$PM/PM_{10}/PM_{2.5}$	40	tons/hr	15217	dscfm	0.005	gr/dscf	1	99.0%	65.22	285.64	0.65	2.9
09(04)	Pebble Lime Silo	$PM/PM_{10}/PM_{2.5}$	19	tons/hr	7609	dscfm	0.005	gr/dscf	1	99.0%	32.61	142.83	0.33	1.4
09(05)	Hydrator Feed Bin #1	$PM/PM_{10}/PM_{2.5}$	25	tons/hr	1413	dscfm	0.005	gr/dscf	1	99.0%	6.06	26.52	0.06	0.3
09(05)	Hydrator Feed Bin #2	$PM/PM_{10}/PM_{2.5}$	25	tons/hr	1413	dscfm	0.005	gr/dscf	1	99.0%	6.06	26.52	0.06	0.3
09(06)	Lime Hydrator #1	$PM/PM_{10}/PM_{2.5}$	19	tons/hr	2069	dscfm	0.005	gr/dscf	1	99.0%	8.87	38.84	0.09	0.4
09(06)	Lime Hydrator #2	$PM/PM_{10}/PM_{2.5}$	19	tons/hr	2069	dscfm	0.005	gr/dscf	1	99.0%	8.87	38.84	0.09	0.4
09(07)	Hydrated Lime Silo[2]	$PM/PM_{10}/PM_{2.5}$	25	tons/hr	15218	dscfm	0.005	gr/dscf	1	99.0%	65.22	285.66	0.65	2.9
09(08)	Lime Dust Silo	$PM/PM_{10}/PM_{2.5}$	1	tons/hr	1630	dscfm	0.005	gr/dscf	1	99.0%	6.99	30.60	0.07	0.3
10	Paved Roadways	PM			48552.23	miles/year	0.1345	lb/VMT	3	50.0%	0.75	3.27	0.37	1.6
10	Paved Roadways	PM_{10}			48552.23	miles/year	0.0269	lb/VMT	3	50.0%	0.15	0.65	0.07	0.3
10	Paved Roadways	$PM_{2.5}$			48552.23	miles/year	0.0066	lb/VMT	3	50.0%	0.04	0.16	0.02	0.1
	Total	PM												14.6
	Total	PM_{10}												13.3
	Total	$PM_{2.5}$												13.1

1 Expected Filter Performance - PM, PM_{10}, and $PM_{2.5}$ assumed to be equivalent
2 EU 09(07), the Hydrated Lime Silo, is the only source in EU 09 or EU 10 where emissions will change from previously submitted values.
3 AP-42 Chapter 13.2.1, control of 50%. Hourly rates reflect the average rates over 8760 hours of operation

Calculation of Existing Actual Emissions for Unit 1

2008 Actual Emissions, tons per month

Parameter	Calculation Basis	Emission Factor	Units	Reference	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Actual Monthly Heat Input			mmBtu	1	562951.9	558336.6	640754.4	362442.8	433426.1	557791.3	557061.7	551385.4	394119.5	582386.1	519919.6	520601.6
PM (filterable)	EF	0.114	lb/mmBtu	2	32.1	31.8	36.5	20.7	24.7	31.8	31.8	31.4	22.5	33.2	29.6	29.7
PM (total)	EF	0.217	lb/mmBtu	3	61.1	60.6	69.6	39.3	47.1	60.6	60.5	59.9	42.8	63.2	56.4	56.5
PM10	EF	0.076	lb/mmBtu	4	21.5	21.3	24.5	13.8	16.6	21.3	21.3	21.1	15.1	22.2	19.9	19.9
PM2.5	EF	0.136	lb/mmBtu	5	38.3	38.0	43.6	24.7	29.5	38.0	37.9	37.5	26.8	39.7	35.4	35.4

1 The permit description lists the maximum hourly heat input rate for Unit 1 at 1080 mmBtu/hr. The heat input rates listed in this table are monthly total actual heat input rates. Average actual hourly heat input rates for each month are well below the 1080 mmBtu/hr value listed in the permit description (determined by dividing the total actual monthly heat input by 24 hours per day and the number of days per month).

2 Filterable PM emission factor based upon testing conducted in April, 2009

Filterable PM test value = 0.114 lb/mmBtu

Average Annual Percent Sulfur = 1.33%

3 Total PM emission factor based upon filterable PM emission factor (0.114 lb/mmBtu) plus the condensable portion calculated using Table 1.1-5 of AP-42, where the condensable PM emission factor = 0.1(S) - 0.03, where S = % sulfur in fuel

4 Filterable PM10 emission factor calculated by applying the percent of PM10 listed in AP-42 Table 1.1-6 (67%) for ESP control to the filterable PM emission factor (0.114 lb/mmBtu)

5 Calculated as filterable PM2.5 plus total condensable emissions, where the filterable PM2.5 emission factor is calculated by applying the percent of PM2.5 listed in AP-42 Table 1.1-6 for ESP control (29%) to the filterable PM emission factor (0.114 lb/mmBtu), then assuming that all of the condensable portion calculated using AP-42 Table 1.1-5 for PC boilers with no FGD controls is PM2.5

2009 Actual Emissions

Parameter	Calculation Basis	Emission Factor	Units	Reference	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Actual Monthly Heat Input			mmBtu		613402.3	472760.2	573735	330616.5	474056.9	441823.7	305629.1	3.1	0	45477.5	443500.3	570133.1
PM (filterable)	Test	0.114	lb/mmBtu	Test	35.0	26.9	32.7	18.8	27.0	25.2	17.5	0.0	0.0	2.6	25.3	32.5
PM (total)	EF	0.211	lb/mmBtu	Test	64.9	50.0	60.7	35.0	50.1	46.7	32.4	0.0	0.0	4.8	46.9	60.3
PM10	EF	0.076	lb/mmBtu	Test	23.4	18.1	21.9	12.6	18.1	16.9	11.7	0.0	0.0	1.7	16.9	21.8
PM2.5	EF	0.131	lb/mmBtu	3	40.0	30.9	37.4	21.6	30.9	28.8	20.0	0.0	0.0	3.0	28.9	37.2

1 The permit description lists the maximum hourly heat input rate for Unit 1 at 1080 mmBtu/hr. The heat input rates listed in this table are monthly total actual heat input rates. Average actual hourly heat input rates for each month are well below the 1080 mmBtu/hr value listed in the permit description (determined by dividing the total actual monthly heat input by 24 hours per day and the number of days per month)

2 Filterable PM emission factor based upon testing conducted in April, 2009

Filterable PM test value = 0.114

Average Annual Percent Sulfur = 1.27%

3 Total PM emission factor based upon filterable PM emission factor (0.114 lb/mmBtu) plus the condensable portion calculated using Table 1.1-5 of AP-42, where the condensable PM emission factor = 0.1(S) - 0.03, where S = % sulfur in fuel

4 Filterable PM10 emission factor calculated by applying the percent of PM10 listed in AP-42 Table 1.1-6 (67%) for ESP control to the filterable PM emission factor (0.114 lb/mmBtu)

5 Calculated as filterable PM2.5 plus total condensable emissions, where the filterable PM2.5 emission factor is calculated by applying the percent of PM2.5 listed in AP-42 Table 1.1-6 for ESP control (29%) to the filterable PM emission factor (0.114 lb/mmBtu), then assuming that all of the condensable portion calculated using AP-42 Table 1.1-5 for PC boilers with no FGD controls is PM2.5

Calculation of Existing Actual Emissions for Unit 1

2010 Actual Emissions

Parameter	Calculation Basis	Emission Factor	Units	Reference	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Actual Monthly Heat Input			mmBtu	1	593833.1	520472	507215.4	504679.2	557246.4	500399.8	486441.6	501411	89589.5	370581.3	537240.4	576480.5
PM (filterable)	Test	0.078	lb/mmBtu	2	23.2	20.3	19.8	19.7	21.7	19.5	19.0	19.6	3.5	14.5	21.0	22.5
PM (total)	EF	0.157	lb/mmBtu	3	46.7	40.9	39.9	39.7	43.8	39.4	38.3	39.4	7.0	29.1	42.3	45.3
PM10	EF	0.052	lb/mmBtu	4	15.5	13.6	13.3	13.2	14.6	13.1	12.7	13.1	2.3	9.7	14.0	15.1
PM2.5	EF	0.102	lb/mmBtu	5	30.3	26.5	25.8	25.7	28.4	25.5	24.8	25.5	4.6	18.9	27.4	29.4

1 The permit description lists the maximum hourly heat input rate for Unit 1 at 1080 mmBtu/hr. The heat input rates listed in this table are monthly total actual heat input rates. Average actual hourly heat input rates for each month are well below the 1080 mmBtu/hr value listed in the permit description (determined by dividing the total actual monthly heat input by 24 hours per day and the number of days per month).

2 Filterable PM emission factor based upon testing conducted in May, 2010

Filterable PM test value = 0.078

Average Annual Percent Sulfur = 1.09%

3 Total PM emission factor based upon filterable PM emission factor (0.078 lb/mmBtu) plus the condensable portion calculated using Table 1.1-5 of AP-42, where the condensable PM emission factor = 0.1(S) - 0.03, where S = % sulfur in fuel

4 Filterable PM10 emission factor calculated by applying the percent of PM10 listed in AP-42 Table 1.1-6 (67%) for ESP control to the filterable PM emission factor (0.078 lb/mmBtu)

5 Calculated as filterable PM2.5 plus total condensable emissions, where the filterable PM2.5 emission factor is calculated by applying the percent of PM2.5 listed in AP-42 Table 1.1-6 for ESP control (29%) to the filterable PM emission factor (0.078 lb/mmBtu), then assuming that all of the condensable portion calculated using AP-42 Table 1.1-5 for PC boilers with no FGD controls is PM2.5

2011 Actual Emissions

Parameter	Calculation Basis	Emission Factor	Units	Reference	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Actual Monthly Heat Input			mmBtu	1	617758	503796	490906	524753	582379	511494	479962	475616	354641	416515	506120	526719
PM (filterable)	Test	0.016	lb/mmBtu	2	4.9	4.0	3.9	4.2	4.7	4.1	3.8	3.8	2.8	3.3	4.0	4.2
PM (total)	EF	0.111	lb/mmBtu	3	34.2	27.9	27.2	29.1	32.3	28.3	26.6	26.3	19.6	23.1	28.0	29.2
PM10	EF	0.011	lb/mmBtu	4	3.3	2.7	2.6	2.8	3.1	2.7	2.6	2.5	1.9	2.2	2.7	2.8
PM2.5	EF	0.099	lb/mmBtu	5	30.7	25.0	24.4	26.1	28.9	25.4	23.9	23.6	17.6	20.7	25.2	26.2

1 The permit description lists the maximum hourly heat input rate for Unit 1 at 1080 mmBtu/hr. The heat input rates listed in this table are monthly total actual heat input rates. Average actual hourly heat input rates for each month are well below the 1080 mmBtu/hr value listed in the permit description (determined by dividing the total actual monthly heat input by 24 hours per day and the number of days per month).

2 Filterable PM emission factor based upon testing conducted in May, 2011

Filterable PM test value = 0.016

Average Annual Percent Sulfur = 1.25%

3 Total PM emission factor based upon filterable PM emission factor (0.016 lb/mmBtu) plus the condensable portion calculated using Table 1.1-5 of AP-42, where the condensable PM emission factor = 0.1(S) - 0.03, where S = % sulfur in fuel

4 Filterable PM10 emission factor calculated by applying the percent of PM10 listed in AP-42 Table 1.1-6 (67%) for ESP control to the filterable PM emission factor (0.016 lb/mmBtu)

5 Calculated as filterable PM2.5 plus total condensable emissions, where the filterable PM2.5 emission factor is calculated by applying the percent of PM2.5 listed in AP-42 Table 1.1-6 for ESP control (29%) to the filterable PM emission factor (0.016 lb/mmBtu), then assuming that all of the condensable portion calculated using AP-42 Table 1.1-5 for PC boilers with no FGD controls is PM2.5

Calculation of Existing Actual Emissions for Unit 1

2012 Actual Emissions

Parameter	Calculation Basis	Emission Factor	Units	Reference	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Actual Monthly Heat Input			mmBtu		531292	442833	488698	414435	492263	427841	438680	442013	285577	584704	568851	535078
PM (filterable)	Test	0.058	lb/mmBtu	Test	15.4	12.8	14.2	12.0	14.3	12.4	12.7	12.8	8.3	17.0	16.5	15.5
PM (total)	EF	0.141	lb/mmBtu	Test	37.5	31.2	34.5	29.2	34.7	30.2	30.9	31.2	20.1	41.2	40.1	37.7
PM10	EF	0.039	lb/mmBtu	Test	10.3	8.6	9.5	8.1	9.6	8.3	8.5	8.6	5.5	11.4	11.1	10.4
PM2.5	EF	0.100	lb/mmBtu	3	26.5	22.1	24.4	20.7	24.6	21.4	21.9	22.1	14.3	29.2	28.4	26.7

1 The permit description lists the maximum hourly heat input rate for Unit 1 at 1080 mmBtu/hr. The heat input rates listed in this table are monthly total actual heat input rates. Average actual hourly heat input rates for each month are well below the 1080 mmBtu/hr value listed in the permit description (determined by dividing the total actual monthly heat input by 24 hours per day and the number of days per month).

2 Filterable PM emission factor based upon testing conducted in April, 2012

Filterable PM test value = 0.058

Average Annual Percent Sulfur = 1.26%

3 Total PM emission factor based upon filterable PM emission factor (0.058 lb/mmBtu) plus the condensable portion calculated using Table 1.1-5 of AP-42, where the condensable PM emission factor = 0.1(S) - 0.03, where S = % sulfur in fuel

4 Filterable PM10 emission factor calculated by applying the percent of PM10 listed in AP-42 Table 1.1-6 (67%) for ESP control to the filterable PM emission factor (0.058 lb/mmBtu)

5 Calculated as filterable PM2.5 plus total condensable emissions, where the filterable PM2.5 emission factor is calculated by applying the percent of PM2.5 listed in AP-42 Table 1.1-6 for ESP control (29%) to the filterable PM emission factor (0.058 lb/mmBtu), then assuming that all of the condensable portion calculated using AP-42 Table 1.1-5 for PC boilers with no FGD controls is PM2.5

		Summary of Baseline Monthly Emissions, tons											
Pollutant	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PM (filterable)	2008	32.1	31.8	36.5	20.7	24.7	31.8	31.8	31.4	22.6	33.2	29.6	29.7
	2009	35.0	26.9	32.7	18.8	27.0	25.2	17.5	0.0	0.0	2.6	25.3	32.6
	2010	23.2	20.3	19.8	19.7	21.7	19.5	19.0	19.6	3.5	14.5	21.0	22.5
	2011	4.9	4.0	3.9	4.2	4.7	4.1	3.8	3.8	2.8	3.3	4.0	4.2
	2012	15.4	12.8	14.2	12.0	14.3	12.4	12.7	12.8	8.3	17.0	16.5	15.5
PM (total)	2008	61.1	60.6	69.6	39.3	47.1	60.6	60.6	59.9	42.8	63.2	56.4	56.6
	2009	64.9	50.0	60.7	35.0	50.1	46.7	32.4	0.0	0.0	4.8	46.9	60.3
	2010	46.7	40.9	39.9	39.7	43.8	39.4	38.3	39.4	7.0	29.1	42.3	45.3
	2011	34.2	27.9	27.2	29.1	32.3	28.3	26.6	26.3	19.6	23.1	28.0	29.2
	2012	37.5	31.2	34.6	29.2	34.7	30.2	30.9	31.2	20.1	41.2	40.1	37.7
PM10	2008	21.5	21.3	24.5	13.8	16.6	21.3	21.3	21.1	15.1	22.2	19.9	19.9
	2009	23.4	18.1	21.9	12.6	18.1	16.9	11.7	0.0	0.0	1.7	16.9	21.8
	2010	15.5	13.6	13.3	13.2	14.6	13.1	12.7	13.1	2.3	9.7	14.0	15.1
	2011	3.3	2.7	2.6	2.8	3.1	2.7	2.6	2.5	1.9	2.2	2.7	2.8
	2012	10.3	8.6	9.5	8.1	9.6	8.3	8.5	8.6	5.5	11.4	11.1	10.4
PM2.5	2008	38.3	38.0	43.6	24.7	29.5	38.0	37.9	37.5	26.8	39.7	35.4	35.4
	2009	40.0	30.9	37.4	21.6	30.9	28.8	20.0	0.0	0.0	3.0	28.9	37.2
	2010	30.3	26.5	25.8	25.7	28.4	25.5	24.8	25.5	4.6	18.9	27.4	29.4
	2011	30.7	25.0	24.4	26.1	28.9	25.4	23.9	23.6	17.6	20.7	25.2	26.2
	2012	26.5	22.1	24.4	20.7	24.6	21.4	21.9	22.1	14.3	29.2	28.4	26.7

Note: Numbers in bold represent those that comprise the highest 24-month average emissions for the 2008-2012 baseline period

Calculation of Existing Actual Emissions for Unit 1

Filterable PM Highest 24-month average annual emissions =	299.6
Total PM Highest 24-month average emissions =	564.6
PM10 Highest 24-month average emissions =	200.8
PM2.5 Highest 24-month average emissions =	351.9

D

APPENDIX D

PROPOSED PERMIT LANGUAGE

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 01 - Indirect Heat Exchanger (Unit 1)

Description:

Pulverized coal-fired, dry-bottom, wall-fired unit equipped with electrostatic precipitator and low NO_x burners
Number two fuel oil used for startup and flame stabilization
Secondary Fuel: up to 3% wood waste of total fuel blend in tons
Maximum continuous rating: 1,080 MMBtu/hr
Construction commenced: 1965 (The electrostatic precipitator was installed in 1971 and rebuilt in 1989. The low-NO_x burners were installed in 1993.)
Control Equipment After Unit 1 Duct Reroute: The existing Unit 2 Dry Flue Gas Desulfurization (DFGD)/Pulse Jet Fabric Filter (PJFF) will be utilized to control Unit 1 and Unit 2 emissions by the applicable compliance dates established by 40 CFR Part 63 Subpart UUUUU, or as extended under Section 112 of the Clean Air Act, and 40 CFR Part 51 Subpart P.

APPLICABLE REGULATIONS:

401 KAR 61:015	**Existing Indirect Heat Exchangers**, applies to existing indirect heat exchangers with a capacity more than 250 MMBtu per hour and commenced before August 17, 1971.
401 KAR 52:060	**Acid Rain Permits**, incorporating by reference 40 CFR Parts 72 to 78, Federal Acid Rain provisions (See Section J).
401 KAR 51:160	**NO_x Requirements for Large Utility and Industrial Boilers**
401 KAR 51:210	**CAIR NO_x annual trading program** (see Section K).
401 KAR 51:220	**CAIR NO_x ozone season trading program** (see Section K).
401 KAR 51:230	**CAIR SO_2 trading program** (see Section K).
401 KAR 63:020	**Potentially hazardous matter or toxic substances.**
40 CFR Part 75	**Continuous Emissions Monitoring** (CEM).
40 CFR 64	**Compliance Assurance Monitoring** (CAM) for particulate matter, ~~unless PM CEMS is installed and operating~~
40 CFR Part 63	Subpart UUUUU, National Emissions Standards for Hazardous Air Pollutants. Coal-and Oil-Fired Electric Utility Steam Generating Units. (Compliance date: April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act.)
40 CFR Part 51	Subpart P, Requirements for Preparation, Adoption and Submittal of Implementation Plans, Protection of Visibility (BART SIP) (Compliance Date: April 30, 2017)

APPLICABLE CONSENT DECREE:

Consent Decree entered September 24, 2007

1. **Operating Limitations:**

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

None.

2. Emission Limitations:

a. Pursuant to 401 KAR 61:015, Section 4(1), particulate matter emissions shall not exceed 0.23 lb/MMBtu based on a three-hour average. See Section I - Compliance Schedule for additional requirements.

Compliance Demonstration Method: To provide assurance that the particulate emission limitation is being met the permittee shall comply with the 3. Testing Requirements below and in Section D.

b. Pursuant to 401 KAR 61:015, Section 4 (3), emissions shall not exceed 40 percent opacity with respect to particulate matter based on a six-minute average, except:

(1) That, for cyclone or pulverized fired indirect heat exchangers, a maximum of sixty (60) percent opacity shall be permissible for not more than one (1) six (6) minute period in any sixty (60) consecutive minutes;

(2) Emissions from an indirect heat exchanger shall not exceed 40 percent opacity based on a six minute average except for emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations.

Compliance Demonstration Method: To provide assurance that the visible emission limitations are being met the permittee shall comply with the 3. Testing Requirements below.

c. Pursuant to 401 KAR 61:015, Section 5 (1), sulfur dioxide emissions shall not exceed 3.3 lb/MMBtu based on a twenty-four-hour average.

Compliance Demonstration Method: To provide assurance that sulfur dioxide emission limit is being met the permittee shall comply with the 4. Specific Monitoring Requirements below.

d. Pursuant to the Kentucky BART SIP, by April 30, 2017, filterable particulate matter emissions shall not exceed 0.030 lb/MMBtu.

Compliance Demonstration Method: To provide assurance that the particulate emission limitation is being met the permittee shall comply with the 3. Testing Requirements below and in Section D.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

e. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

3. Testing Requirements:

a. Pursuant to 401 KAR 50:045, the permittee shall submit within six months of the issuance date of the final permit (V-05-082) a schedule, to conduct a performance test for particulate compliance within one year of issuance of Permit Number V-05-082.

b. Testing shall be conducted in accordance with 401 KAR 50:045, Performance Tests, and pursuant to 40 CFR 64.4(c)(1), the testing shall be conducted under conditions representative of maximum emissions potential under anticipated operating conditions at the pollutant-specific emissions unit.

c. In accordance with 4.b Specific Monitoring Requirements, the permittee shall submit a schedule within six months from the date of issuance of the final permit (V-05-082) to conduct testing within one year following the issuance of Permit Number V-05-082 to establish or re-establish the correlation between opacity and particulate emissions.

d. If no additional stack tests are performed pursuant to 4.b(2) Specific Monitoring Requirements, the permittee shall conduct a performance test for particulate emissions by the start of the fourth year of this permit to demonstrate compliance with the applicable standard.

e. The permittee shall determine the opacity of emissions from the stack by US EPA Reference Method 9 pm a b-weekly basis, or more frequently if requested by the Division. In lieu of Reference Method 9 readings, the permittee may use COM data for compliance determinations.

f. Beginning in calendar year 2008, and continuing annually thereafter, the permittee shall conduct a PM performance test. This requirement may be satisfied by PM performance testing conducted to satisfy other requirements of this permit. The permittee may perform biennial rather than annual testing provided that:

(1) two of the most recently completed test results from tests conducted in accordance with 40 CFR Part 60, Appendix A-1,

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Method 5 demonstrate that the PM emissions are equal to or less than 0.015 lb/MMBtu or;

(2) the Unit is equipped with a PM CEMS in accordance with paragraphs 88 through 95 of the Consent Decree.

The permittee 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 [Consent Decree entered September 24, 2007, paragraph 86].

g. The reference and monitoring methods and procedures for determining compliance with PM Emission Rates shall be those specified in 40 CFR Part 60, Appendix Al, Method 5. Use of any particular method shall conform to the US EPA requirements specified in 40 CFR Part 60, Appendix A and 40 CFR 60.48a (b) and (e), or any federally approved method contained in the Kentucky SIP. The permittee shall calculate the PM Emission Rates from the stack test results in accordance with 40 CFR 60.8(f). The results of each PM stack test shall be submitted to the US EPA within 30 days of completion of each test [Consent Decree entered September 24, 2007, paragraph 87].

h. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

4. **Specific Monitoring Requirements:**

a. Pursuant to 401 KAR 61:005, Section 3, Performance Specification 1 of 40 CFR 60, Appendix B, and 401 KAR 52:020, Section 26, a continuous opacity monitoring (COM) system shall conform to requirements of these sections which include installing, calibrating, operating, and maintaining the continuous monitoring system for accurate opacity measurement. Excluding exempted time periods, if any six-minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate:

(1) Accept the concurrent readout from the COM and perform an inspection of the control equipment and make any necessary repairs or;

(2) Within 30 minutes after COM indicates exceedance of the opacity standard, determine opacity using Reference Method 9 if emissions are visible, inspect the COM and/or the control equipment, and

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

make any necessary repairs. If a Reference Method 9 cannot be performed, the reason for not performing the test shall be documented.

b. Pursuant to 401 KAR 52:020, Section 26, and 401 KAR 61:005, Section 3(6), to meet the monitoring requirement for particulate matter, the permittee shall use ~~a~~ the existing COM for both Units 1 and 2. ~~unless a PM CEMS is installed and operated as described below~~. Pursuant to 40 CFR 64.4(a)(1), opacity shall be used as an indicator of particulate matter emissions. Pursuant to 40 CFR Part 64.4(c)(1), testing shall be conducted to establish the level of opacity that will be used as an indicator of particulate matter emissions. There may be short-term exceedances during the testing period required to establish the opacity indicator level. These exceedances will not be considered noncompliance periods since the testing is required to establish a permit requirement. The opacity indicator level shall be established at a level that provides reasonable assurance that particulate matter emissions are in compliance when opacity is equal to or less than the indicator level. Excluding exempted time periods:

(1) If any three hour opacity value exceeds the indicator level, the permittee shall, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs.

(2) If five percent or greater of the COM data (three-hour average of opacity values) recorded in a calendar quarter show excursions above the opacity indicator level, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate standard while operating at representative conditions. The permittee shall submit a compliance test protocol as pursuant to 401 KAR 50:045, Performance Tests, before conducting the test. The Division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance Tests.

c. The opacity indicator range will be determined based on PM emissions testing in 4.b. The CAM plan will be completed and implemented according to the following schedule:

(1) EKPC shall complete testing to establish the indicator range within 180 days after the compliance demonstration specified in Section G.4.e. of this permit.

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(2) EKPC shall submit an updated CAM plan within 180 days after the indicator range testing is completed.

(3) EKPC shall then comply with the approved CAM plan for Units 1 and 2.

d. ~~Unless a PM CEMS is installed and operated as described below,~~ The permittee shall monitor the ESP primary/secondary current and voltage, as submitted in the approved CAM plan. Corrective action shall be initiated when an excursion occurs outside the indicator ranges established in the approved CAM plan for those parameters.

e. Pursuant to 401 KAR 61:005, Section 3 and Performance Specification 2 of Appendix B to 40 CFR 60 or 40 CFR 75, Appendix A, and 401 KAR 52:020, Section 26, continuous emission monitoring systems (CEMS) shall be installed, calibrated, maintained, and operated for measuring nitrogen oxide, sulfur dioxide and either oxygen or carbon dioxide emissions. Excluding exempted time periods, if any 24-hour average sulfur dioxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and/or the CEM system and make any necessary repairs or take corrective actions as soon as practicable.

f. Pursuant to 401 KAR 61:015, Section 6(1), the sulfur content of solid fuels, as burned shall be determined in accordance with methods specified by the Division.

g. Pursuant to 401 KAR 61:015, Section 6(3) the rate of each fuel burned shall be measured daily and recorded. The heating value and ash content of fuels shall be ascertained at least once per week and recorded. The average electrical output, and the minimum and maximum hourly generation rate shall be measured and recorded daily.

h. Pursuant to 401 KAR 61:005, Section 3(5), the Division may provide a temporary exemption from the monitoring and reporting requirements of 401 KAR 61:005, Section 3, for the continuous monitoring system during any period of monitoring system malfunction, provided that the source owner or operator shows, to the Division's satisfaction, that the malfunction was unavoidable and is being repaired as expeditiously as practicable.

i. The permittee shall monitor the duration of the start up.

~~j. The permittee shall install, certify, and operate PM CEMS by December 31, 2012 [Consent Decree entered September 24, 2007, paragraph 90].~~

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

~~(1) Operation of the PM CEMS shall be in accordance with 40 CFR Part 60, App. B, Performance Specification 11, and App. F Procedure 2.~~

~~(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.~~

~~(3) The permittee shall maintain, in an electronic database, the hourly average emission values of the PM CEMS in lb/MMBtu.~~

~~(4) The permittee shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating [Consent Decree entered September 24, 2007, paragraph 88].~~

~~(5) No later than March 24, 2008, the permittee shall submit to US EPA for review and approval pursuant to Section XIII (Review and Approval of Submittals) of the Consent Decree a plan for the installation and certification of each PM CEMS [Consent Decree entered September 24, 2007, paragraph 89].~~

~~(6) No later than 120 days prior to December 31, 2012, the permittee shall submit to the US EPA for review and approval pursuant to Section XIII (Review and Approval of Submittals) of the Consent Decree a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating the PM CEMS. Following US EPA's approval of the protocol, the permittee shall thereafter operate the PM CEMS in accordance with the approved protocol [Consent Decree entered September 24, 2007, paragraph 91].~~

~~(7) In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, the permittee shall use the criteria set forth in 40 CFR Part 60, App. B, Performance Specification II, and App. F Procedure 2. The permittee 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 [Consent Decree entered September 24, 2007, paragraph 92].~~

~~(8) No later than 90 days after the permittee begins operation of the PM CEMS, the permittee shall conduct tests of the PM CEMS to demonstrate compliance with the PM CEMS installation and~~

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

~~certification plan submitted to and approved by EPA in accordance with paragraph 89 [Consent Decree entered September 24, 2007, paragraph 93].~~

~~(9) (9) The permittee shall operate the PM CEMS for at least two years. After two years of operation, the permittee may attempt to demonstrate that it is infeasible to continue operating PM CEMS. As part of that demonstration, the permittee shall submit an alternative PM monitoring plan for review and approval by the US EPA. The plan shall explain the basis for stopping operation of the PM CEMS and propose an alternative monitoring plan. If the US EPA disapproves the alternative PM monitoring plan, or if the US EPA rejects the permittee's claim that it is infeasible to continue operating PM CEMS, such disagreement is subject to Section XVI (Dispute Resolution) of the Consent Decree [Consent Decree entered September 24, 2007, paragraph 94].~~

~~(10) 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) The permittee 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 the US EPA determines that operation is no longer feasible, the permittee shall be entitled to discontinue operation of and remove the PM CEMS [Consent Decree entered September 24, 2007, paragraph 95].~~

~~(11) Following the installation of the PM CEMS, the permittee shall begin and continue to report to the US EPA, pursuant to Section XII (Periodic Reporting) of the Consent Decree, the data recorded by the PM CEMS, expressed in lb/MMBtu on a 3-hour, 24 hour, 30-day, and 365-day rolling average basis in electronic format, as required in subparagraphs (1)-(4) above [Consent Decree entered September 24, 2007, paragraph 103].~~

~~(12) Although stack testing shall be used to determine compliance with the PM Emission Rate established by the Consent Decree, data from the PM CEMS shall be used, at a minimum, to monitor~~

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

~~progress in reducing PM emissions. Nothing in the 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 [Consent Decree entered September 24, 2007, paragraph 104].~~

k. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

5. **Specific Record Keeping Requirements:**

a. In accordance with 401 KAR 61:005, Section 3(15) and 61:015, Section 6, the permittee shall maintain a file of all information reported in the quarterly summaries, with the exception that records shall be maintained for five years.

b. The permittee shall maintain records of:

(1) Each fuel analysis;

(2) The rate of fuel burned for each fuel type, on a daily basis;

(3) The heating value and ash content on a weekly basis;

(4) The average electrical output and the minimum and maximum hourly generation rate on a daily basis;

(5) When no excess emissions have occurred and the continuous monitoring system(s) have not been inoperative, repaired, or adjusted;

(6) Data collected either by the continuous monitoring systems or as necessary to convert monitoring data to the units of the applicable standard;

(7) Results of all compliance tests; and

(8) Percentage of the COM data (excluding exempted time periods) showing excursions above the opacity standard and the opacity indicator level.

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c. Records of primary/secondary voltage and current, and corrective actions shall be maintained with long-term operational records for five years. This requirement is waived if a PM CEMS is installed and operated.

d. The permittee shall keep visible observation records and Method 9 observations in a designated logbook and/or an electronic format. Records shall be maintained for five years.

e. The permittee shall record the duration of start up.

f. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

6. **Specific Reporting Requirements:**

a. Pursuant to 401 KAR 61:005, Section 3, minimum data requirements which follow shall be maintained and furnished in the format specified by the Division:

(1) Owners or operators of facilities required to install continuous monitoring systems for opacity and sulfur dioxide or those utilizing fuel sampling and analysis for sulfur dioxide emissions shall submit for every calendar quarter, a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the emission standard averaging period which is a 24-hour averaging period. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(2) Owners or operators of facilities required to install continuous monitoring systems for opacity shall submit for every calendar quarter a written report of excess emission and the nature and cause of emissions. The summary shall consist of the magnitude in actual percent opacity of six-minute averages of opacity greater than the opacity standard in the applicable standard for each hour of operation of the facility. Average values may be obtained by integration over the averaging period or by arithmetically averaging a minimum of four equally spaced, instantaneous opacity measurements per minute. Any time period exempted shall be considered before determining the excess average of opacity. Opacity data shall be reported in electronic format acceptable to the Division.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

(3) For gaseous measurements the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages shall not appear in the written summary, but shall be provided in electronic format only.

(4) The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustments shall be reported. Proof of continuous monitoring system performance is required as specified by the Division whenever system repairs or adjustments have been made.

b. The permittee shall report the number of excursions (excluding exempted time periods) above the opacity standard, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity standard in each calendar quarter.

c. Pursuant to 401 KAR 61:015, in the event of start-up, the permittee shall report:

(1) The type of start-up (cold, warm, or hot);

(2) Whether or not the duration of the start-up exceeded the manufacturer's recommendation or typical, historical durations, and if so, an explanation of why the start-up exceeded recommended or typical durations.

d. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

7. **Specific Control Equipment Operating Conditions:**

a. The electrostatic precipitator shall be continuously operated to maximize PM emission reductions, consistent with manufacturer's specifications, the operational design and maintenance limitations of the units, and good engineering practice. The permittee shall at a minimum:

(1) energize each section of the ESP, regardless of whether that action is needed to comply with opacity limits;

(2) maintain the energy or power levels delivered to the ESP to achieve the greatest possible removal of PM;

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

(3) make best efforts to expeditiously repair and return to service transformer-rectifier sets when they fail; and

(4) inspect for, and schedule for repair, any openings in ESP casings and ductwork to minimize air leakage. [Consent Decree entered September 24, 2007, Section VII.A]

b. The permittee shall optimize the plate-cleaning and discharge-electrode-cleaning systems for the ESPs by varying the cycle time, cycle frequency, rapper-vibrator intensity, and number of strikes per cleaning event, to minimize PM emissions. [Consent Decree entered September 24, 2007, Section VII.A]

c. Pursuant to 401 KAR 52:020, Section 26, records regarding the maintenance of the electrostatic precipitator shall be maintained.

d. The permittee shall implement the technology specified in the Kentucky BART SIP by utilizing the Unit 2 DFGD/PJFF control train for emissions from Unit 1.

e. The control equipment shall be operated and maintained in accordance with manufacturer's specifications and standard operating practices to ensure the emission unit is in compliance with applicable requirements. [401 KAR 50:055, Section 2.]

f. See Section E for additional requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 02 - Indirect Heat Exchanger (Unit 2)

Description:

Pulverized coal-fired, dry-bottom, wall-fired unit equipped with electrostatic precipitator, low NO_x burners, Flue Gas Desulfurization (FGD), Selective Catalytic Reduction (SCR), and fabric filter Number two fuel oil used for startup and flame stabilization
Secondary Fuel: up to 3% wood waste of total fuel blend in tons
Maximum continuous rating: 2,089 MMBtu/hr
Construction commenced: 1969. The electrostatic precipitator was installed in 1971, and rebuilt in 1989.
The Low-NO_x burners were installed in 1994. The FGD and fabric filter will be in operation by 6-30- 2012 The fabric filter will replace the electrostatic precipitator. The SCR will be in operation by December 31, 2012.

APPLICABLE REGULATIONS:

401 KAR 61:015	**Existing Indirect Heat Exchangers**, applies to existing indirect heat exchangers with a capacity more than 250 MMBtu per hour and commenced before August 17, 1971.
401 KAR 51:160	**NO_x Requirements for Large Utility and Industrial Boilers**
401 KAR 51:210	**CAIR NO_x annual trading program** (see Section K).
401 KAR 51:220	**CAIR NO_x ozone season trading program** (see Section K).
401 KAR 51:230	**CAIR SO_2 trading program** (see Section K)
401 KAR 52:060	**Acid rain permits**, incorporating the Federal Acid Rain provisions as codified in 40 CFR Parts 72 to 78 (see Section J).
401 KAR 63:020	**Potentially hazardous matter or toxic substances.**
40 CFR Part 75	**Continuous Emissions Monitoring** (CEM).
40 CFR 64	**Compliance Assurance Monitoring** (CAM) for particulate matter, unless PM CEMS is installed and operating
40 CFR Part 63	Subpart UUUUU, National Emissions Standards for Hazardous Air Pollutants. Coal-and Oil-Fired Electric Utility Steam Generating Units. (Compliance date: April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act)
40 CFR Part 51	Subpart P, Requirements for Preparation, Adoption and Submittal of Implementation Plans, Protection of Visibility (BART SIP) (Compliance Date: April 30, 2017)

APPLICABLE CONSENT DECREE:

Consent Decree entered September 24, 2007

1. **Operating Limitations:**

   None.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. **Emission Limitations:**

a. Pursuant to 401 KAR 61:015, Section 4(1), particulate matter emissions shall not exceed 0.23 lb/MMBtu based on a three-hour average. See Section I - Compliance Schedule for additional requirements.

Compliance Demonstration Method: To provide assurance that the particulate matter emission limitation is being met the permittee shall comply with requirements in 3. Testing Requirements below and in Section D.

b. Pursuant to 401 KAR 61:015, Section 4 (3), emissions shall not exceed 40 percent opacity with respect to particulate matter based on a six-minute average except:

(1) That, for cyclone or pulverized fired indirect heat exchangers, a maximum of 60 percent opacity shall be permissible for not more than one six-minute period in any 60 consecutive minutes;

(2) Emissions from an indirect heat exchanger shall not exceed 40 percent opacity based on a six-minute average except for emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations.

Compliance Demonstration Method: To provide assurance that the visible emission limitation is being met the permittee shall comply with the 3. Testing Requirements below.

c. Pursuant to 401 KAR 61:015, Section 5 (1), sulfur dioxide emissions shall not exceed 3.3 lb/MMBtu based on a 24-hour average. Beginning on June 30, 2012, the permittee shall install and commence continuous operation of FGD technology on Unit 2 so as to achieve, and thereafter maintain, a 30-day Rolling Average SO_2 Removal Efficiency of at least 95 percent or a 30-Day Rolling Average SO_2 Emission Rate of no greater than 0.100 lb/MMBtu [Consent Decree entered September 24, 2007, paragraph 65].

Compliance Demonstration Method: In determining Emission Rates for SO_2, the permittee shall use CEMS in accordance with the procedures specified in 40 CFR Part 75 [Consent Decree entered September 24, 2007, paragraph 79]. If the percent removal efficiency requirement is used to demonstrate compliance, the outlet SO_2 Emission Rate and the inlet SO_2 Emission Rate shall be determined based on the data generated in

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

accordance with 40 CFR Part 75.15 (1999) (using SO_2 CEMS data from both the inlet and outlet of the control device). [Consent Decree entered September 24, 2007, paragraph 80]. See also 4. Specific Monitoring Requirements below and Section D.

d. Beginning on December 31, 2012, the permittee shall install and commence continuous operation of year-round SCR technology on Unit 2 so as to achieve, and thereafter maintain, a NO_x, 30-Day Rolling Average Emission Rate not greater than 0.080, lb/IVIMBtu [Consent Decree entered September 24, 2007, paragraph 53].

Compliance Demonstration Method: In determining Emission Rates for NO_x, the permittee shall use CEMS in accordance with the procedures specified in 40 CFR Part 75 [Consent Decree entered September 24, 2007, paragraph 63]. See also 4. Specific Monitoring Requirements below and Section D.

e. Pursuant to the Kentucky BART SIP, by April 30, 2017, filterable particulate matter emissions shall not exceed 0.030 lb/MMBtu.

Compliance Demonstration Method: To provide assurance that the particulate emission limitation is being met the permittee shall comply with the 3. Testing Requirements below and in Section D.

f. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

3. **Testing Requirements:**

a. Pursuant to 401 KAR 50:045, the permittee shall submit within six months of the issuance date of the final permit (V-05-082) a schedule, to conduct a performance test for particulate compliance within one year of issuance of Permit Number V-05-082.

b. Testing shall be conducted in accordance with 401 KAR 50:045, Performance Tests, and pursuant to 40 CFR 64.4(c)(1), the testing shall be conducted under conditions representative of maximum emissions potential under anticipated operating conditions at the pollutant-specific emissions unit.

c. In accordance with 4.b Specific Monitoring Requirements, the permittee shall submit a schedule within six months from the date of issuance of the final permit (V-05-082) to conduct testing within one year following the

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

issuance of Permit Number V-05-082 to establish or re-establish the correlation between opacity and particulate emissions.

d. If no additional stack tests are performed pursuant to 4.b(2) Specific Monitoring Requirements, the permittee shall conduct a performance test for particulate emissions by the start of the fourth year of this permit to demonstrate compliance with the applicable standard.

e. The permittee shall determine the opacity of emissions from the stack by US EPA Reference Method 9 on bi-weekly basis, or more frequently if requested by the Division. In lieu of Reference Method 9 readings, the permittee may use COM data for compliance determinations

f. Beginning in calendar year 2008, and continuing annually thereafter, the permittee shall conduct a PM performance test. This requirement may be satisfied by PM performance testing conducted to satisfy other requirements of this permit. The permittee may perform biennial rather than annual testing provided that:

(1) two of the most recently completed test results from tests conducted in accordance with 40 CFR Part 60, Appendix A-1, Method 5 demonstrate that the PM emissions are equal to or less than 0.015 lb/MMBtu or;

(2) the Unit is equipped with a PM CEMS in accordance with paragraphs 88 through 95 of the Consent Decree.

The permittee 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 [Consent Decree entered September 24, 2007, paragraph 86].

g. The reference and monitoring methods and procedures for determining compliance with PM Emission Rates shall be those specified in 40 CFR Part 60, Appendix A, Method 5. Use of any particular method shall conform to the US EPA requirements specified in 40 CFR Part 60, Appendix A and 40 CFR 60.48a (b) and (e), or any federally approved method contained in the Kentucky SIP. The permittee shall calculate the PM Emission Rates from the stack test results in accordance with 40 CFR 60.8(0. The results of each PM stack test shall be submitted to the US EPA within 30 days of completion of each test [Consent Decree entered September 24, 2007, paragraph 87]. The results of each PM stack test shall be submitted to the Division within 30 days of completion of each test [401 KAR 50:045].

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

h. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

4. **Specific Monitoring Requirements:**

a. Pursuant to 401 KAR 61:005, Section 3, Performance Specification 1 of 40 CFR 60, Appendix B, and 401 KAR 52:020, Section 10, a continuous opacity monitoring (COM) system shall conform to requirements of these sections which include installing, calibrating, operating, and maintaining the continuous monitoring system for accurate opacity measurement. Excluding exempted time periods, if any six-minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate:

(1) Accept the concurrent readout from the COM and perform an inspection of the control equipment and make any necessary repairs or;

(2) Within 30 minutes after the COM indicates exceedance of the opacity standard, determine opacity using Reference Method 9 if emissions are visible, inspect the COM and/or the control equipment, and make any necessary repairs. If a Reference Method 9 cannot be performed, the reason for not performing the test shall be documented.

b. Pursuant to 401 KAR 52:020, Section 26, and 401 KAR 61:005, Section 3(6), to meet the monitoring requirement for particulate matter, the permittee shall use ~~a~~ the existing COM for both Units 1 and 2. Pursuant to 40 CFR 64.4(a)(1) ~~and the CAM plan filed on October 15, 2005~~, opacity shall be used as an indicator of particulate matter emissions. Pursuant to 40 CFR Part 64.4(c)(1), testing shall be conducted to establish the level of opacity that will be used as an indicator of particulate matter emissions. There may be short-term exceedances during the testing period required to establish the opacity indicator level. These exceedances will not be considered noncompliance periods since the testing is required to establish a permit requirement. The opacity indicator level shall be established at a level that provides reasonable assurance that particulate matter emissions are in compliance when opacity is equal to or less than the indicator level. Excluding exempted time periods:

(1) If any three hour opacity value exceeds the indicator level, the permittee shall, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

(2) If five percent or greater of the COM data (three-hour average of opacity values) recorded in a calendar quarter show excursions above the opacity indicator level, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate standard while operating at representative conditions. The permittee shall submit a compliance test protocol as required by 401 KAR 50:045, Performance Tests, of this permit before conducting the test. The Division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance Tests.

c. The opacity indicator range will be determined based on PM emissions testing in 4.b. The CAM plan will be completed and implemented according to the following schedule:

(1) EKPC shall complete testing to establish the indicator range within 180 days after the compliance demonstration specified in G.4.e.

(2) EKPC shall submit an updated CAM plan within 180 days after the indicator range testing is completed.

(3) EKPC shall then comply with the approved CAM plan for Units 1 and 2.

c. The permittee shall monitor the ESP primary/secondary current and voltage, as described in the approved CAM plan. Corrective action shall be initiated when an excursion occurs outside the indicator ranges established in the approved CAM plan for those parameters.

d. Pursuant to 401 KAR 61:005, Section 3 and Performance Specification 2 of Append ix B to 40 CFR 60 or 40 CFR 75, Appendix A, and 401 KAR 52:020, Section 26, continuous emission monitoring systems (C

e. EMS) shall be installed, calibrated, maintained, and operated for measuring nitrogen oxide, sulfur dioxide and either oxygen or carbon dioxide emissions. Excluding exempted time periods, if any 24-hour average sulfur dioxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and/or the CEM system and make any necessary repairs or take corrective actions as soon as practicable.

f. Pursuant to 401 KAR 61:015, Section 6(1), the sulfur content of solid fuels, as burned shall be determined in accordance with methods specified by the Division.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

g. Pursuant to 401 KAR 61:015, Section 6(3) the rate of each fuel burned shall be measured daily and recorded. The heating value and ash content of fuels shall be ascertained at least once per week and recorded. The average electrical output, and the minimum and maximum hourly generation rate shall be measured and recorded daily.

h. Pursuant to 401 KAR 61:005, Section 3(5), the Division may provide a temporary exemption from the monitoring and reporting requirements of 401 KAR 61:005, Section 3, for the continuous monitoring system during any period of monitoring system malfunction, provided that the source owner or operator shows, to the Division's satisfaction, that the malfunction was unavoidable and is being repaired as expeditiously as practicable.

i. The permittee shall monitor the duration of the start up.

j. <u>The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.</u>

5. **<u>Specific Record Keeping Requirements:</u>**

a. In accordance with 401 KAR 61:005, Section 3 and 61:015, Section 6, the owner or operator shall maintain a file of all information reported in the quarterly summaries, with the exception that records shall be maintained for a period of five years.

b. The permittee shall maintain records of:

(1) Each fuel analysis;

(2) The rate of fuel burned for each fuel type, on a daily basis;

(3) The heating value and ash content on a weekly basis;

(4) The average electrical output and the minimum and maximum hourly generation rate on a daily basis;

(5) When no excess emissions have occurred and the continuous monitoring system(s) have not been inoperative, repaired, or adjusted;

(6) Data collected either by the continuous monitoring systems or as necessary to convert monitoring data to the units of the applicable standard;

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

(7) Results of all compliance tests; and

(8) Percentage of the COM data (excluding exempted time periods) showing excursions above the opacity standard and the opacity indicator level.

c. Records of primary/secondary voltage and current, and corrective actions shall be maintained with long-term operational records for a period of five years.

d. The permittee shall keep visible observation records and Reference Method 9 observations in a designated logbook and/or an electronic format. Records shall be maintained for five years.

e. The permittee shall record the duration of start up.

f. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

6. **Specific Reporting Requirements:**

a. Pursuant to 401 KAR 61:005, Section 3, minimum data requirements which follow shall be maintained and furnished in the format specified by the Division.

(1) Owners or operators of facilities required to install continuous monitoring systems for opacity and sulfur dioxide or those utilizing fuel sampling and analysis for sulfur dioxide emissions shall submit for every calendar quarter, a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the emission standard averaging period which is a 24-hour averaging period. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(2) Owners or operators of facilities required to install continuous monitoring systems for opacity shall submit for every calendar quarter a written report of excess emission and the nature and cause of emissions. The summary shall consist of the magnitude in actual percent opacity of six-minute averages of opacity greater than the opacity standard in the applicable standard for each hour of operation of the facility. Average values may be obtained by

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

integration over the averaging period or by arithmetically averaging a minimum of four equally spaced, instantaneous opacity measurements per minute. Any time period exempted shall be considered before determining the excess average of opacity. Opacity data shall be reported in electronic format acceptable to the Division.

(3) For gaseous measurements the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages shall not appear in the written summary, but shall be provided in electronic format only.

(4) The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustments shall be reported. Proof of continuous monitoring system performance is required as specified by the Division whenever system repairs or adjustments have been made.

b. The permittee shall report the number of excursions (excluding exempted time periods) above the opacity standard, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity standard in each calendar quarter.

c. Pursuant to 401 KAR 61:015, in the event of start-up, the permittee shall report:

(1) The type of start-up (cold, warm, or hot);

(2) Whether or not the duration of the start-up exceeded the manufacturer's recommendation or typical, historical durations, and if so, an explanation of why the start-up exceeded recommended or typical durations.

d. The permittee shall comply with the applicable provisions of 40 CFR Part 63 Subpart UUUUU by April 16, 2015 or the date specified in a compliance extension under Section 112 of the Clean Air Act, whichever is later.

7. **Specific Control Equipment Operating Conditions:**

a. The electrostatic precipitator or fabric filter once installed, shall be continuously operated to maximize PM emission reductions, consistent with manufacturer's specification, the operational design and maintenance limitations of the units, and good engineering practice. Until the fabric filter is in operation, the permittee shall at a minimum:

(1) energize each section of the ESP, regardless of whether that action is needed to comply with opacity limits;

(2) maintain the energy or power levels delivered to the ESP to achieve the greatest possible removal of PM;

(3) make best efforts to expeditiously repair and return to service transformer-rectifier sets when they fail; and

(4) inspect for, and schedule for repair, any opening in ESP casings and ductwork to minimize air leakage. [Consent Decree entered September 24, 2007, Section VII.A]

b. The permittee shall optimize the plate-cleaning and discharge-electrode-cleaning systems for the ESP by varying the cycle time, cycle frequency, rapper-vibrator intensity, and number of strikes per cleaning event, to minimize PM emissions. [Consent Decree entered September 24, 2007, Section VII.A]

c. Beginning on December 31, 2012, the permittee shall continuously operate the SCR at all times that Unit 2 is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the SCR for minimizing emissions to the extent practicable [Consent Decree entered September 24, 2007, paragraph 55].

d. Beginning on June 30, 2012, the permittee shall continuously operate the FGD at all times that Unit 2 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 [Consent Decree entered September 24, 2007, paragraph 67].

e. The control equipment shall be operated and maintained in accordance with manufacturer's specifications and standard operating practices to ensure the emission units are in compliance with applicable requirements. [401 KAR 50:055, Section 2].

f. Pursuant to 401 KAR 52:020, Section 26, records regarding the maintenance of the control equipment shall be maintained.

g. See Section E for additional requirements.

Permit Number: V-05-082 R2

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 09 - Pebble Lime and Waste Product Handling System

Emission Unit	Description	Operating Rate	Control Devices	Construction Commenced
09-01	New Waste Product Silo #1	40 tons/hour	Fabric Filter	2010
09-02	New Waste Product Silo #2	40 tons/hour	Fabric Filter	2010
09-03	Vacuum System #1 and #2	40 tons/hour, each	Fabric Filter	2010
09-04	Pebble Lime Silo	19 tons/hour	Fabric Filter	2010
09-05	Hydrator Product Transfer Bin #1 and #2	25 tons/hour, each	Fabric Filter	2010
09-06	Lime Hydrator #1 and #2	19 tons/hour, each	Fabric Filter	2010
09-07	Hydrated Lime Silo	~~25~~ 50 tons/hour	Fabric Filter	2010
09-08	Lime Dust Silo	1 ton/hour	Fabric Filter	2010

Applicable Regulations:

401 KAR 59:010 — **New process operations**, applicable to each affected facility or source associated with a process operation commenced after July 2, 1975, which is not subject to another emission standard with respect to particulates.

40 CFR Part 64 — **Compliance assurance monitoring** applies to PM emissions from Emission Unit 09-03 (Vacuum System #1 and #2), Emission Unit 09-04 (Pebble Lime Silo) and Emission Unit 09-07 (Hydrated Lime Silo)

1. Operating Limitations

The permittee shall install fabric filters with a minimum design specification of 0.005 gr/dscf. See 7. Specific Control Equipment Operating Conditions for additional requirements.

2. Emission Limitations

a. The permittee shall not cause, suffer, allow, or permit any continuous emission into the open air from a control device or stack associated with any affected facility which is equal to or greater than 20 percent opacity [401 KAR 59:010].

Compliance Demonstration Method: Refer to 3. Testing Requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. Particulate matter emissions from each stack or control device shall not exceed:

Emission Unit	Description	Emission Limit
09-01	New Waste Product Silo #1	$17.31P^{0.16}$ lbs/hr
09-02	New Waste Product Silo #2	$17.31P^{0.16}$ lbs/hr
09-03	Vacuum System #1 and #2	$17.31P^{0.16}$ lbs/hr, each
09-04	Pebble Lime Silo	$3.59P^{0.62}$ lbs/hr
09-05	Hydrator Product Transfer Bin #1 and #2	$3.59P^{0.62}$ lbs/hr, each
09-06	Lime Hydrator #1 and #2	$3.59P^{0.62}$ lbs/hr, each
09-07	Hydrated Lime Silo	~~3.59~~ $17.31P^{0.62}$ lbs/hr
09-08	Lime Dust Silo	$3.59P^{0.62}$ lbs/hr

Where P = process weight rate in tons/hour. "Process weight rate" means a rate established as follows:

(1) For continuous or long-run steady state operations, the total process weight for the entire period of continuous operation or for a typical portion thereof, divided by the number of hours of such period or portion thereof.

(2) For cyclical or batch unit operations, or unit processes, the total process weight for a period that covers a complete operation or an integral number of cycles, divided by the hours of actual process operation during such a period.

(3) Where the nature of any process operation or the design of any equipment is such as to permit more than one (1) interpretation of this definition, the interpretation which results in the minimum value for allowable emission shall apply [401 KAR 59:010, Section 2(3)].

Compliance Demonstration Method: Refer to 3. Testing Requirements.

3. Testing Requirements

a. The permittee shall demonstrate compliance with emission standards within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup [401 KAR 50:055, Section 2(1)(a)]. Subsequent compliance

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

demonstrations shall be calculated based upon emission factors obtained from testing and the amount of material processed on a monthly basis, as follows:

$$Emissions\ (lbs/hr) = \frac{Monthly\ Material\ Processed\ (tons)}{Monthly\ Hours\ of\ Operation} \times EmissionFactor\ (lbs/ton)$$

b. In conducting performance tests the permittee shall use as reference methods and procedures the test methods in 40 CFR Part 60 Appendix A.

c. The permittee shall determine the opacity of emissions from each stack by US EPA Method 9 weekly, or more frequently if requested by the Division [401 KAR 52:020, Section 26].

4. **Specific Monitoring Requirements**

a. Applicable to Emission Unit 09-03 (Vacuum System #1 and #2), Emission Unit 09-04 (Pebble Lime Silo) and Emission Unit 09-07 (Hydrated Lime Silo) only: Pursuant to 40 CFR 64.4(a)(1) and the CAM plan filed with the application, opacity shall be used as indicator of particulate matter emissions. The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a daily weekday (Monday through Friday) basis and maintain a log of the observations. If any visible emissions are observed, the permittee shall initiate corrective action within 24 hours to return the fabric filter to normal operation [40 CFR Part 64, 401 KAR 52:020, Section 26].

b. Pressure drop across the fabric filters will be monitored through the use of a strip recorder or other continuous recording device. The permittee shall maintain strip recorder (or other continuous recording device) charts. In case of out-of-range indications, the permittee shall log the date and time of the excursion, the reason for the excursion (if known) and the measures taken to correct the excursion [40 CFR Part 64, 401 KAR 52:020, Section 26].

c. The permittee shall monitor the amount in tons of material processed and waste product produced on a monthly basis [401 KAR 52:020, Section 26].

5. **Recordkeeping Requirements**

a. The permittee shall record each periodic inspection required under paragraph 4.a. Specific Monitoring Requirements, including dates and any corrective actions taken, in a logbook (in written or electronic format). The permittee shall keep the logbook onsite and make hard or electronic copies (whichever is requested) of the logbook available to the Division upon request [40 CFR Part 64, 401 KAR 52:020, Section 26].

b. The permittee shall maintain records related to pressure drop strip recorder (or other continuous recording device) charts and shall keep the logbook onsite and make hard or electronic copies (whichever is requested) of the logbook available to the Division upon request [40 CFR Part 64, 401 KAR 52:020, Section 26].

6. **Specific Reporting Requirements**

a. The permittee shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards in 2. Emission Limitations, including reports of opacity observations [401 KAR 52:020, Section 26].

b. Refer to Section F for additional requirements.

7. **Specific Control Equipment Operating Conditions**

a. Control equipment shall be operated in accordance with manufacturer's specifications and standard operating practices to maintain compliance with permitted emission limits and [401 KAR 50:055, Section 2].

b. Records regarding maintenance of the control equipment shall be maintained [401 KAR 52:020, Section 26].

c. Refer to Section E for additional requirements.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)))))))))	CASE NO. 2013-00259

EXHIBIT 7

DIRECT TESTIMONY OF JULIA J. TUCKER

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 21, 2013

I. Introduction

Q. Please state your name and title.

A. Julia J. Tucker, PE. I am the Director of Power Supply Planning for East Kentucky Power Cooperative, Inc. ("EKPC").

Q. Please provide an overview of your education and professional background.

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 and have maintained my Continuing Education requirements for that license. I completed 18 hours towards a Masters of Business Administration degree. I have been employed in various engineering, planning and management roles with East Kentucky Power Cooperative for over 26 years.

Q. What are your job responsibilities at EKPC?

A. I am responsible for all generation / resource planning functions at EKPC, including day ahead planning, mid-term planning, long-term resource planning, renewable resource 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 define the need for the requested reroute of ducts at the Cooper Station so that Cooper #1 may be tied into the Air Quality Control System ("AQCS") for Cooper #2. (the "Project") and to provide background of how the Project was chosen as EKPC's best alternative.

II. Background

Q. Did you have a role in helping to prepare EKPC's last Integrated Resource Plan?

A. Yes, the EKPC 2012 Integrated Resource Plan ("IRP") was developed under my direction.

Q. How would you summarize the results of EKPC's last IRP?

A. There were four steps to EKPC's Plan of Action:

- Continue to monitor economic and load conditions.
- Continue to refine its Demand Side Management ("DSM") evaluations and develop a reasonable and financially viable comprehensive DSM Plan.
- Issue a Request for Proposals ("RFP") for Power Supply resources to address the existing capacity affected by the U.S. Environmental Protection Agency's ("EPA") Mercury Air Toxics Standards ("MATS") rules.
- Continue to evaluate and monitor joint operating opportunities.

Q. What was the primary factor in suggesting that EKPC would need to acquire up to an additional 300 MW of capacity?

A. EKPC had to consider the impacts of the MATS issued by the EPA in February 2012 on its existing generation fleet. The Spurlock Plant units are state of the art facilities that can be readily modified to meet all of the new rules. Likewise, the Cooper 2 unit with its recent additional of pollution control equipment can also meet the new rules. At the time of finalizing the IRP, the oldest units in the EKPC fleet, Dale Station and Cooper 1, were expected to require capital intensive retrofits to meet operating requirements under MATS. EKPC needed to find the most economic alternatives to meet its power supply requirements and meet MATS. EKPC needed to mitigate the potential risk of losing approximately 300 MW of existing power supply resources (Dale Station – 200 MW;

Cooper 1 – 116 MW) while maintaining an economic and reliable power supply to its member owners.

Q. When did the IRP indicate that this new capacity needed to be available in order to satisfy EKPC's capacity requirements?

A. The IRP was conducted on a "business as usual" basis for EKPC. Since EKPC is already short on capacity to meet its winter peak load plus a planning reserve margin, then the capacity would need to be replaced as soon as it would no longer be viable due to MATS. This date was assumed to be in 2015.

Q. Did the Company's full integration into PJM eliminate the anticipated future gap in generation capacity?

A. EKPC's integration into PJM changed its capacity requirements from being based on winter peak load to being summer peak load. Additionally, EKPC's load shape diversity with the PJM market significantly reduced the percentage amount of capacity that must be carried for planning reserves. This significantly impacts the amount of capacity that East Kentucky Power must either supply or purchase in the capacity market within PJM. It is possible that the 300 MW could be retired without any replacement capacity, those impacts would be reflected in EKPC's cost to serve its load. The replacement capacity issue became strictly an economic issue when EKPC joined PJM, and no longer had reliability impacts.

Q. What steps did EKPC take to fill an anticipated future gap in generation capacity?

A. EKPC hired The Brattle Group ("Brattle") to manage its 2012 RFP for long-term power supply. Specifically to develop and market the RFP, to screen and evaluate proposals, select a short list and report on a recommended course of action.

III. The 2012 Request for Proposals

Q. When did EKPC's Board authorize the Company to conduct an RFP?

A. EKPC staff presented the IRP results to the Board of Directors and received approval from the Board on March 13, 2012 to file the IRP with the Kentucky Public Service Commission. That IRP defined the need to issue the RFP for power supply resources. Staff informed the Board at that same time that an RFP would be issued to request up to 300 MW of power supply resources to address the capacity that would be affected by MATS, as recommended in the IRP.

Q. Who was on the team that conducted the RFP on behalf of EKPC?

A. David Crews, Senior Vice President of Power Supply; Julia J. Tucker, Director of Power Supply Planning; Jeff Brandt, Manager of Alternative Fuels and Renewables; Fernie Williams, Senior Analyst; David Samford, Outside Counsel.

Q. What was your role in managing the RFP that EKPC conducted in 2012?

A. I was EKPC's lead contact with Brattle and coordinated the transfer of data between EKPC and Brattle. I also reviewed and evaluated the analyses completed by both companies.

Q. Did you know at the outset of the RFP process that the Company would be submitting self-build options as part of the RFP?

A. Yes.

Q. How did EKPC insulate the team that conducted the RFP from the team that submitted self-build options?

A. EKPC developed a "Chinese Wall" between its planning and production teams. The Power Production team was responsible for developing EKPC self-build options and was not permitted to interact with EKPC's Power Supply Planning team. Each of these groups reported to different Senior Vice Presidents, thus isolating information exchange within the company.

Q. How long was the "Chinese Wall" in place?

A. The "Chinese Wall" remained in place until after Brattle and the Power Supply Planning team had made their recommendation to develop the Project to EKPC's management. At that point no other EKPC self-build projects remained on the RFP Short List to fulfill the balance of the anticipated capacity need described in the RFP.

Q. Are you aware of anything that occurred during the course of the RFP, or the subsequent evaluation of bids received as part of the RFP, that would in any way compromise the integrity of the RFP process?

A. No.

Q. Did EKPC engage the service of any consultants to assist with conducting the RFP and evaluating its results?

A. Yes, as I mentioned previously, EKPC hired Brattle.

Q. Why did EKPC select Brattle to assist with conducting the RFP?

A. EKPC solicited proposals from various consulting companies and chose Brattle based on their experience and risk analysis expertise.

Q. What was Brattle's role in assisting with the conduct of the RFP?

A. Brattle was hired to assist EKPC, develop and market the RFP, screen proposals, select a Short List, and report on a recommended course of action. This was a collaborative effort in which Brattle leveraged EKPC's Power Supply Planning staff, analytical resources, and data.

Q. What was the timeline for the RFP?

A. EKPC filed its 2012 IRP with the PSC on April 20, 2012. EKPC hired Brattle in April 2012. EKPC announced its intention to issue an RFP in a press release on April 23, 2012. The RFP was released and the web site went "live" on June 8, 2012. EKPC posted notices in the *Public Utilities Fortnightly*, Platt's *Megawatt Daily*, and SNL *Power Daily*. The advertisements were published on or around the week of June 25, 2012. In addition to creating the RFP web site, Brattle conducted an informational Webinar for potential bidders on June 27. Prospective bidders were required to submit a non-binding Notice of Intent to Bid and Confidentiality Agreement by July 3, 2012. Proposals in response to the RFP were due in electronic format by August 30, 2012, followed by hard copy five days later.

Q. Can you provide a copy of the RFP for the Commission's reference?

A. Yes. A copy of the solicitation is attached and incorporated into my testimony as Exhibit JJT-1.

Q. How many bids were received in response to the RFP?

A. In total EKPC received over 100 proposals from 65 bidders.

Q. Describe the respective roles of the EKPC bid evaluation team and Brattle's bid evaluation team.

A. EKPC provided fuel cost projections, market price projections, production costing analysis and other variable cost pricing information as needed. Brattle took the output from the variable cost modeling and paired it with their fixed costs analysis and projections to develop an overall comparison of options.

Q. How did EKPC and Brattle arrive at a "short list" for the RFP?

A. Brattle and EKPC selected six proposals for the Short List by identifying the proposal in each category with the highest NPV per MW-year. In addition, EKPC chose to include a seventh proposal in the Short List.

Q. When did Brattle make its recommendation to EKPC regarding the results of the RFP?

A. Brattle made its initial recommendation to EKPC regarding the results in a letter report dated January 28, 2013.

Q. What did Brattle recommend?

A. The last paragraph of the above referenced letter report states "To sum up, our analysis indicates that the proposed Cooper 1 retrofit would add very substantial value for a modest investment. Based on my understanding of EKPC's objectives, constraints, and circumstances, it is the proposal with the highest value added for EKPC."

Q. Was the recommendation tendered by Brattle consistent with your own professional judgment and experience?

A. Yes.

Q. After you completed your review of the bids, was there a clear degree of separation between the Cooper #1 Retrofit self-build option and other bids received?

A. Yes. A modest investment yields over 100 MW of capacity at an existing unit that can leverage other EKPC investment and expertise. The Project will pay for itself in a short time period and help improve operating costs for the second unit at the facility. The Project was a clear economic winner.

Q. Does the Project fulfill the entirety of the anticipated future capacity need sought to be filled by the RFP?

A. No, the Project fulfills only about 1/3 of the capacity sought in the RFP.

Q. Does the fact that the Cooper Option will only be a partial answer to acquiring up to 300 MW of additional capacity increase or decrease the risks associated with developing new capacity?

A. Splitting the 300 MW of capacity between options spreads the technology and operational risks.

Q. Has EKPC determined how it will fill the balance of the anticipated future capacity gap?

A. EKPC continues to negotiate with Short List bidders to finalize the remaining portion of the capacity gap.

Q. What remains to be done to complete the RFP process?

A. EKPC and Brattle need to complete the negotiations with potential partners and finalize a contract(s).

Q. When does EKPC anticipate that the RFP process will be complete?

A. The process should be complete by the end of the third quarter of 2013.

Q. Does moving forward with the Project adversely impact EKPC's ability to complete the RFP process?

A. No.

Q. Are there other reasons, beyond the economic analysis, that the Project is a good option for EKPC?

A. The Project allows EKPC to leverage existing investments, resources and operating expertise that already exists at the Cooper Station. It keeps jobs at the plant along with local suppliers. Both units will utilize state of the art environmental technology, providing cleaner energy to Kentuckians.

Q. **How has EKPC's Board been kept apprised of the progress of the 2012 RFP from its initial approval of the RFP through the filing of the Application?**

A. Multiple presentations have been made to the Board to keep them apprised of the RFP process results. The Board approved the Project and the regulatory filings required for the Project.

Q. **Is the Company concerned that the Cooper Option does not help achieve its strategic objective to diversify its portfolio?**

A. The Project does leave EKPC with 116 MW more coal-fired capacity than it would have if Cooper 1 was retired, and thus with that much more capacity exposed to coal market price risk and the potential for a carbon tax and/or carbon regulations. However, given the uncertainty of future regulations, the modest amount of investment needed to continue use of an existing facility until regulations are further vetted is a prudent use of member owner funds.

IV. Conclusion

Q. **Would you care to summarize your testimony?**

A. EKPC solicited a wide array of options to meet its compliance plan for MATS. The response to its RFP was substantial and offered many alternatives. The most valuable alternatives when compared to the PJM market that EKPC operates within are those with minimal capital investment and favorable energy costs. The Project is a clear economic benefit for EKPC's member owners and allows further use of an existing plant with existing infrastructure and demonstrated operational excellence.

Q. Does this conclude your testimony?

A. Yes.

EXHIBITS

Document	Exhibit
EKPC RFP Solicitation	1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	**CASE NO. 2013-00259**

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 21st day of August, 2013.

Greg M. Willoughby
Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

EAST KENTUCKY POWER COOPERATIVE

ALL SOURCE LONG-TERM REQUEST FOR PROPOSALS 2012

[JULY 5, 2012: TWO DATES REVISED; SEE ALSO THE FAQs ON WEBSITE FOR AMENDMENTS AND CLARIFICATIONS.]

RFP Issued:	**June 8, 2012**
Supporting, Required Forms Issued:	**June 15, 2012**
Notice of Intent to Submit Proposal Due:	**July 10, 2012**
Required Forms with Revisions Issued:	**July 13, 2012**
Proposal Submittal Deadline:	**August 30, 2012**
RFP website:	**www.ekpc-rfp2012.com**
RFP email:	**ekpc-rfp@brattle.com**

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1. INTRODUCTION

1.1 OVERVIEW

East Kentucky Power Cooperative (EKPC) is issuing this All Source Long-Term Request for Proposals 2012 (RFP) to obtain new resources through a solicitation of interest from utilities, power marketers, project owners and project developers who desire to place a bid or bids and meet the minimum qualifications as described herein (Bidders or Participants). EKPC has formally applied to the Kentucky Public Service Commission for approval to transfer functional control of its system into the PJM Interconnection (PJM) and will systematically assume for purposes of this RFP that EKPC is a full member of PJM.[1] Thus, all Bidders should assume that they will deliver the capacity and/or energy resources to EKPC within PJM and under the PJM rules and procedures.

Subject to this and other conditions discussed below, EKPC will consider the following resources in this RFP:

- New construction of conventional generation technologies and all fuel types to include turnkey ownership, joint ownership or other alternatives;
- Existing conventional generation (a share of a plant could be accepted);
- New and existing renewable generation (as discussed below).

Pursuant to policies of the Kentucky Public Service Commission (PSC) and consistent with EKPC's Integrated Resource Plan (IRP) filed with the PSC on April 20, 2012,[2] EKPC seeks to acquire up to 300 megawatts (MW) of new resources, with an on-line date of October 2015. EKPC will consider resources that come on-line up to two years later, on or about October 2017, but will have to evaluate any additional costs it may incur under this later on-line date. As discussed in the IRP, one reason for the need for new resources is the impact of the EPA's Mercury and Air Toxics Standards (MATS) regulation. EKPC will evaluate the costs of retrofitting its older coal plants to comply with MATS. EKPC intends to offer a self-build option for this RFP.[3] EKPC is not soliciting and will not accept capacity from PJM Demand Response resources. EKPC is developing its own demand side management resources.

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1 EKPC intends that during the full period of the contracts that come from this RFP it would be a signatory to the PJM OATT, the PJM Reliability Assurance Agreement, and the PJM Operating Agreement.

2 EKPC, *2012 Integrated Resource Plan*, with Technical Appendices, all Redacted, April 20, 2012.

3 EKPC has established a wall to ensure that no cost information will be shared between its Power Production business unit, which will prepare the self-build proposal, and its Power Supply business unit, which will be involved in evaluating the bids that are received. The Brattle Group, as Independent Procurement Manager, also

For new conventional and/or renewable generation facilities, Participants may submit Bids in two forms. The first form is a Power Purchase Agreement (PPA) with EKPC, which is contained in the set of Required, Supporting Forms (Required Forms), which will be put on the RFP website on June 15, 2012. This is discussed below in Section 5. EKPC will consider PPAs for capacity in the EKPC Locational Deliverability Area (LDA) in PJM. EKPC will consider PPAs for energy delivered to:

- the EKPC load zone in PJM;
- the AEP-Dayton (AD) Hub;
- other delivery points that are fully described such that EKPC can determine the equivalent costs for delivery in comparing alternatives.

A PPA for bundled energy and capacity would need to specify both the energy delivery point and the LDA. EKPC would consider a bundled bid with the energy delivered to the AEP-Dayton Hub and the capacity delivered to the PJM LDA for AEP, and would evaluate any incremental costs or benefits from that arrangement. EKPC will consider energy and capacity from new or existing renewable generation resources.

One of the Required Forms is a signed draft PPA, which at the Bidder's discretion will contain terms, such as pricing terms, that are binding for 60 days from August 30, 2012. This signed form must be submitted for each PPA Bid. The conditions for the PPA Bids are discussed below in Section 2.3.4. Again, all Required Forms with their terms will be posted to the "ekpc-rfp2012" website on Friday, June 15, 2012. The final revisions to the Forms will be posted to the website by Tuesday, July 10, 2012.

The second form of the Bid is Facility Ownership by EKPC. For Facility Ownership, the sale would be conducted pursuant to a Purchase and Sale Agreement (PSA) and related documentation, which is found in Required Forms. This is the contract form under which a Participant would sell full or part ownership in an existing plant or would develop and cause to be constructed a fully permitted, operational generation facility, which would be sold in entirety or in part to EKPC at project completion. EKPC solicits both full and partial ownership shares, as long as the MWs of the project are within the minimum and maximum bounds for MW discussed below and other conditions are met. The Required Forms for Facility Ownership Bids would not need to be executable, but the conditions as discussed in the Required Forms would have to be met by any Bidder, or a Facility Ownership Bid may not be deemed acceptable to EKPC.

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will have no contact with the Power Production business unit staff that are involved in the preparation of a self-build proposal.

EKPC has three sites in its service territory suitable for locating a gas-fired combined cycle combustion turbine facility (CCGT) or a gas-fired single cycle combustion turbine facility. A Participant could propose to build at any of these sites under the Facility Ownership and PSA arrangement. EKPC is not accepting a Bid for a PPA at any of these sites. For these three sites, EKPC will be responsible for building the fuel pipeline from the nearest natural gas pipeline interconnection to the input point of the generation plant. The three sites have different expected costs for this fuel pipeline connection, which the Bidders may wish to consider. EKPC will also secure the air and water permits. Additional information and the conditions for the use of the EKPC sites are described in a Required Form on development and siting status. EKPC may submit self-build proposals at one or more of its sites.

Additional general conditions are that Contracts for new resources should have a minimum of 50 MW for any conventional resource and 5 MW for any renewable resource, as further specified in Section 2.3.2 below. This is a long-term procurement, so the length of any PPA should be at least five years and can be longer at Bidder's discretion. EKPC's 2012 IRP showed a preference for dispatchable and operationally flexible resources, but EKPC will evaluate any reasonable and fully described resource that a Bidder offers.

East Kentucky Power Cooperative, Inc. is committed to environmental stewardship while safely providing affordable, reliable power to its members. Therefore, EKPC will also consider proposals for energy and capacity from renewable generation resources. The renewable resources' bids must be a minimum of 5 MW (single resource or an aggregate in one Bid that is greater than or equal to 5 MW). The duration of the renewable energy resource contract(s) should range from a minimum of 5 years to the life of the facility. The capacity and/or energy must be deliverable to EKPC's Delivery Points as described herein. Renewable energy resources may include, but are not limited to:

- Wind
- Biomass
- Solar (electric or thermal)
- Hydro
- Geothermal
- Recycled energy (waste heat, etc.)

This RFP is open to those parties who currently own, propose to develop, or have rights to a renewable energy generating facility 5 MW or larger. Preference will be given to renewable projects that are in the state of Kentucky. Bidders may submit multiple proposals to fulfill the resource request. The proposal must be based upon a proven technology.

EKPC will retain all environmental attributes associated with Bidder's proposed bid energy, including but not limited to renewable energy credits, green tags, greenhouse gas or carbon credits, and any other emissions attributes. EKPC has engaged the services of The Brattle Group to act as an independent procurement manager and perform a comparative analysis and evaluation of proposals received under this solicitation. EKPC reserves the right to retain any other independent consulting service that it may deem necessary or advisable. The final decisions with regard to acceptance or rejection of any or all proposals are specifically reserved to EKPC, subject to the approval of the Kentucky PSC.

1.2 SCHEDULE

The schedule for this RFP process is set forth in Table 1. This schedule is subject to adjustment and any changes will be posted immediately on the website.

Table 1: Major Milestones for the RFP

No.	Major Milestones for the RFP	Dates
1	RFP document and Form 1 issue date	Friday, 6/8/2012
2	RFP Website live	Friday, 6/8/2012
3	Date to register at the Website to receive all further information with respect to the RFP. Potential bidders can continue to register up to Tuesday, 7/3/2012.	Wednesday, 6/13/2012
4	On the website, all Required Forms for a Bid will be posted, which will explain the information requirements for the Bids. An objective is to allow Bidders to fully explain their Bids, while systematically collecting as much information as possible in machine-readable format. Suggestions for improvements will be accepted by email through Tuesday, 7/3/2012, and the final Forms distributed on Tuesday, 7/10/2012	Friday, 6/15/2012
5	Webinar to answer questions of prospective bidders	Wednesday, 6/27/2012
6	**Due date for Notice of Intent to Submit Proposal (Reset on July 2, 2012)**	**Tuesday, 7/10/2012**
7	**Final versions of Bidder Response Forms, including Excel Forms 10 - 13 that should include binding values for 60 days, except as explicitly indicated by bidder, as discussed in Draft Forms 10 - 13.**	**Friday, 7/13/2012**
8	Proposals due in electronic form	Thursday, 8/30/2012
9	Proposals due with wet signed orginal in hardcopy	Wednesday, 9/5/2012
10	Date up to which the executable PPA Bids must be good, which is 60 days after the PPA Bids are submitted. EKPC may exercise the right to execute any such PPA Bid.	Sunday, 10/28/2012
11	Select Short Listed proposals, assuming that the RFP is going to continue.	Thursday, 11/1/2012
12	Execute Project Agreements, if not executed earlier.	1/1 - 1/15/2013

1.3 Disclaimer for Rejecting Bids and/or Terminating this RFP

This RFP does not constitute an offer to buy and creates no obligation to execute any Agreement or to enter into a transaction under an Agreement as a consequence of the RFP. EKPC shall retain the right at any time, in its sole discretion, to reject any Bid on the grounds that it does not conform to the terms and conditions of this RFP and reserves the right to request information at any time during the solicitation process. EKPC also retains the discretion, in its sole judgment, to: (a) reject any Bid on the basis that it does not provide sufficient ratepayer benefit or that it would impose conditions that EKPC determines are impractical or inappropriate; (b) implement the appropriate criteria for the evaluation and selection of Bids; (c) negotiate with any Participant to maximize ratepayer benefits; (d) modify this RFP as it deems appropriate to implement the RFP and to comply with applicable law or other direction provided by the PSC; and (e) terminate the RFP should the PSC not authorize EKPC to execute Agreements of the type sought through this RFP. In addition, EKPC reserves the right to either suspend or terminate this RFP at any time for any reason whatsoever. EKPC will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this paragraph to any Participant, whether submitting a Bid or not.

1.4 Contact Information

The Brattle Group (Brattle) is serving as the Independent Procurement Manager (IPM) for this RFP process. Proposals in response to this RFP are due at the IPM's offices no later than 4PM Pacific Daylight Time (PDT) on Thursday, August 30, 2012.

Proposals are to be submitted by mail, e-mail, fax, or hand delivery to the IPM. Faxed or e-mailed proposals must be followed up by a signed original that is delivered by mail or overnight courier no later than 4PM PDT on September 5, 2012.

All correspondence should be directed to the IPM at the following address:

EKPC All Source RFP c/o The Brattle Group
201 Mission St., Suite 2800
San Francisco, CA 94105
Phone: 415.217.1000
Fax: 415.217.1099
E-mail: ekpc-rfp@brattle.com
Web Site: www.ekpc-rfp2012.com

2. EKPC SITUATION AND THE RFP GOALS

2.1 HISTORY

East Kentucky Power Cooperative, Inc. (EKPC) is headquartered in Winchester, KY and provides electric power and energy to 16 member distribution cooperatives serving approximately 511,000 meters in 87 Kentucky counties. EKPC is a member of the National Renewable Cooperative Organization. EKPC's existing resource portfolio consists of approximately 2,500 MW of coal and gas generating capacity, 15 MW of Landfill Gas generation, 170 MW of South East Power Administration (SEPA) hydro power, and various power purchase contracts. EKPC has applied for membership in PJM, and expects to be a member during the entire period of any contracts that result from this RFP. In addition to being a member of PJM, EKPC expects to maintain interconnections with the following other utilities/markets:

- KU/LG&E/PPL
- Tennessee Valley Authority (TVA)

Pursuant to policies of the Kentucky Public Service Commission (PSC) and consistent with EKPC's Integrated Resource Plan (IRP) filed with the PSC on April 20, 2012,[4] EKPC seeks to acquire up to 300 megawatts (MW) of new resources, with on-line date on October 2015. EKPC will consider resources that come on-line up to two years later, on or about October 2017, but must evaluate any additional costs it may incur under this later on-line date. As discussed in the IRP, one reason for the need for new resources is the impact of the U.S. EPA's MATS policy. EKPC will evaluate the costs of retrofitting its older coal plants to comply with MATS. EKPC intends to offer a self-build option for this RFP. EKPC is not soliciting and will not accept bids for capacity from PJM Demand Response resources. EKPC has its own demand side management resources that it is developing.

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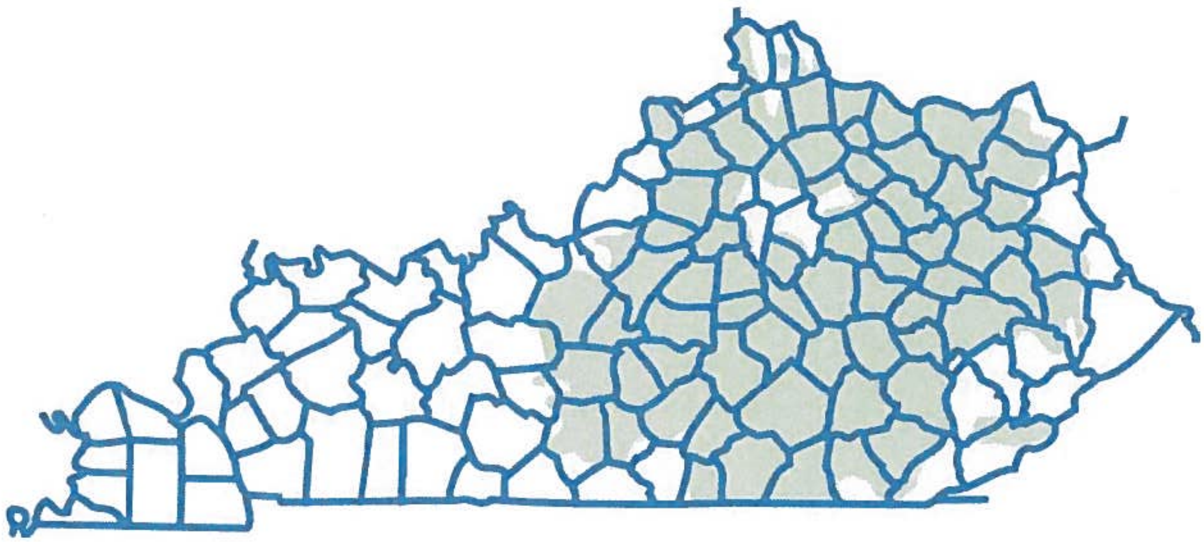
[4] EKPC, *2012 Integrated Resource Plan*, with Technical Appendices, all Redacted, April 20, 2012.

2.2 System Map



The above map shows the territory of EKPC and its member systems.

2.3 RFP Goals

2.3.1 EKPC Resource Needs

EKPC submitted its Integrated Resource Plan (IRP) to the Kentucky Public Service Commission on April 20, 2012. Based on its IRP, EKPC projects it will need approximately 300 MWs of capacity by October 2015. As mentioned previously, EKPC will consider resources that come on-line up to two years later, that is, on or about October 2017, but must consider any additional costs it may incur under a later on-line date.

To meet this projected need, EKPC is seeking Bids from resources that meet the specifications set forth in Section 4 "Submission of Proposals and Eligibility Requirements." Attractive bids will be those that allow EKPC to produce energy and capacity products compatible with EKPC's requirements, and contribute to the other criteria specified in Section 6 "Proposal Evaluations."

In this solicitation, EKPC is willing to consider a wide range of intermediate and long-term resources that meet all or part of its requirements. EKPC will evaluate the benefits and costs of Bids in light of its existing portfolio of supply and demand-side resources.

EKPC must fully understand operational limitations of each Bid due to environmental constraints, such as air quality limitations. If applicable, Participants should specify all operational constraints the resource will be required to meet, such as those needed to comply with local Air Board requirements as well as other permitting requirements.

In addition, EKPC intends to bid any resources selected as a result of this RFP into the PJM market. EKPC will rely on any selected Bidder's attestations as to expected commercial operations date (COD), delivery date, or other time sensitive information contained in the response. As such, it is expected that any negotiated agreement will contain terms including but not limited to liquidated damages and/or replacement capacity costs at the prevailing market price for capacity at the time of expected delivery and until such time as performance is satisfied under the terms of said agreement.

2.3.2 Resources

EKPC will consider proposals (1) to enter into power purchase agreements and (2) to purchase new or existing generation resources (full or partial). Also, EKPC will consider Bids from conventional and renewable generation resources. EKPC has a preference for physical resources or PPAs that are based on physical resources. EKPC is not willing to enter into purely financial contracts to satisfy this RFP.

Conventional Generation

For purposes of this solicitation, the term "conventional generation" includes combined cycle and simple cycle (combustion turbine) technologies fueled by natural gas or bio-fuels. It also includes existing coal, nuclear and hydro facilities. Minimum Bid size is 50 MW from each facility.

Renewable Resources

EKPC will consider energy and capacity from new or existing renewable generation resources, including facilities burning biodiesel, digester gas, landfill gas or municipal solid waste, fuel cells using renewable fuels, geothermal facilities, ocean wave, ocean thermal and tidal current facilities, solar photovoltaic and solar thermal facilities, small hydroelectric (30 megawatts or less) facilities and wind generators. The minimum Bid size is 5 MW from each facility.

2.3.3 Facility Ownership: Generation Characteristics

Each facility will be operated to provide products as needed to conform to the requirements of PJM. For some resources, this is expected to include multiple daily starts and stops, rapid turndown of and ramp up within the unit's capabilities and full compliance with environmental permit conditions. This is to be satisfied by fully and accurately completing the Required Forms.

Load Following Generation

Bids to develop and sell a shaping or load following facility to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form on combined cycle plants. The ability to meet these characteristics will be given additional weight in the evaluation process. Bids other than natural gas-fired technologies should respond to the appendices in a full and complete manner indicating where information is not applicable and provide additional information where appropriate in order to allow EKPC to fully evaluate its bids. Bids must meet all federal and state laws and be able to secure all permits.

Peaking Generation

Bids to develop and sell a peaking facility to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form on simple cycle combustion turbines. The ability to meet these characteristics will be given significant weight in the evaluation process. Bids other than gas-fired technologies should respond to the appendices in a full and complete manner indicating where information is not applicable and provide additional information where appropriate in order to allow EKPC to fully evaluate its Bid. Bids must meet all federal and state laws and be able to secure all permits.

Baseload Generation

Bids to develop and sell baseload generation to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form. Bids must meet all federal and state laws and be able to secure all permits.

2.3.4 Contract Options

All PPA Bids should include a draft PPA as part of the bid. Unless clearly set forth in the draft PPA to the contrary, the terms of the PPA shall be binding upon the Participant for 60 days from the date of submission, August 30, 2012,which is until October 28, 2012. Any section(s) or terms of the draft PPA which the Participant intends to be non-binding on the Participant (and subject to further negotiation) shall be clearly designated in the draft PPA. At the end of that period on October 29, 2012, EKPC may ask the Bidder to refresh the Bid for another 60 days, and the Bidder can respond accordingly, including any updates as to the binding nature of the terms of the draft PPA, so as to continue to be considered in the Short List negotiation of this RFP. Failure of a Bidder to provide a draft Purchase Power Agreement as set forth herein may result in disqualification of the Participant's Bid.

All Facility Ownership/PSA Bids must fully meet the conditions that are imposed on that kind of bid. These conditions will be stated in the Forms on Facility Ownership/PSA Bids that will be issued on June

15, 2012. EKPC wants to be certain that Facility Ownership Bidders planning to use an EKPC site are providing accurate and complete cost numbers on which they are prepared to execute. However, EKPC recognizes that building on one of its sites is likely to require additional negotiations, so EKPC is not expecting a fully-executable Facility Ownership Bid. Failure of a Participant to fill the details of the Required Forms for Facility Ownership/PSA option may result in disqualification of the Participant's Bid.

PPAs

EKPC is seeking PPA Bids for new and existing renewables and new and existing conventional generation technologies, including technologies capable of running on multiple fuels. The Required Forms will contain all forms for the PPA Bids. EKPC will provide the Required Forms on the website on June 15, 2012 and update certain of the Required Forms by July 10, 2012. As discussed above, each PPA Bid at the Bidder's discretion can have terms, such as price terms, that are binding for 60 days from its submission on August 30, 2012, which is until October 28, 2012.

For PPA Bids from natural gas-fired facilities, EKPC's preferred contract structure is a fuel conversion (tolling) structure. The documentation requested in the Required Forms will be generally structured to accommodate gas-fired units and a fuel conversion agreement. Participants offering a PPA other than a fuel conversion agreement for a gas-fired facility should adapt the documentation by selecting or deleting the optional elements as appropriate or making such other adjustments as necessary and appropriate for the technology and fuel-type offered. See the Required Forms.

Regardless of the contract structure offered, Participants are requested to specify contract quantities, fixed O&M costs, variable O&M costs, contract heat rate(s) (where applicable), and other parameters to aid EKPC in comparing Bids, which will be requested on the Required Forms.

Participants can submit fixed-price PPA Bids. Participants can also submit PPA Bids that use indexed pricing, as described below.

- PPAs must meet all of PJM requirements for Capacity transactions, as contained in the PJM Business Manuals,
- PPA must meet all of the PJM requirements for Energy transaction, as contained in the PJM Business Manuals,
- Variable O&M, Fixed O&M, Variable Energy and Fired Hour Charge: A Participant shall indicate in its Bid an initial price for each of these components. If the Participant elects to use indexed pricing, the Participant should fully describe the indexation approach by filling out the appropriate Required Forms, which will be sent out on June 15, 2012,

- Capacity Payment Rate: A Participant shall indicate in its Bid an initial price for capacity. If the Participant elects to use indexed pricing, the Participant should fully describe the indexation approach by filling out the appropriate Required Forms, which will be sent out on June 15, 2012.

Purchase and Sale Agreements (PSAs)

EKPC is seeking PSA Bids for Facility Ownership of new conventional generation technologies, including technologies capable of running on multiple fuels, whereby the Participant would design, develop, permit, construct and commission the facility. EKPC has three existing sites for such a facility, as discussed in the Required Forms. EKPC would take ownership of the facility once it is constructed, tested and accepted. Bids must include milestone guarantees and performance guarantees for the completed facility. Participants must completely fill out, but will not have to provide any executable Required Forms for a PSA.

Participants can submit fixed-price PSA Bids, as will be described in the Required Forms.

The PSA term sheet will be provided in the Required Forms. Generation characteristics that EKPC is seeking are described in Section 2.3.3 "Facility Ownership." EKPC plans to update the Required Form for the PSA Bids by July 10, 2012.

Purchase Price: A Participant shall indicate in its Bid a purchase price, as of the date the Agreement is executed by EKPC, for a Project offered in a PSA Bid.

The Delivery Points are:

- The EKPC load zone for energy and EKPC LDA for capacity,
- The AEP-Dayton (AD) Hub for energy and PJM LDA for AEP for capacity,
- other delivery points that are fully described such that EKPC can determine the equivalent costs for delivery in comparing alternatives.

As part of an individual Bid, a Participant may submit Bid variations, with each Bid variation indexing certain components. For example a Participant offering a PPA could offer one variation with a fixed capacity price and another variation may index the capacity price, while both Bid variations index the other pricing components. This information should be provided in the Required Forms.

3. TRANSMISSION AND DELIVERY INFORMATION

3.1. PJM MEMBERSHIP TO BE ASSUMED

EKPC considers transmission reliability to be of utmost importance, and the Bidder should specify what arrangements it intends to make to deliver the power reliably. EKPC has formally applied to the Kentucky Public Service Commission to join and is expecting to be a full member of PJM during the term of any contract resulting from this RFP. If the Bidder is also a member of PJM, then the transmission arrangements will be governed by the PJM protocols. If the Bidder is outside of PJM, the Bidder will have to explain the expected cost and reliability of transmission to the PJM system and to the EKPC Delivery Points.

Any modifications or additions to EKPC's system, including interconnection, transmission, or communications facilities, required by a Bidder for power delivery to EKPC's system, shall be subject to review and approval by EKPC. Expenses relating to any such modifications or additions will be included or inferred by EKPC in the price evaluation of the Bidder's proposal.

4. SUBMISSION OF PROPOSALS AND ELIGIBILITY REQUIREMENTS

4.1. OVERVIEW OF PROCESS

The bid process will include the events as indicated on the schedule in Section 1.2. June 8, 2012 is the release of the RFP and the opening of the website. On July 3, 2012, interested Bidders will be requested to submit a Notice of Intent to Submit Proposal form. Proposals will due August 30, 2012. The proposals will be screened and non-conforming offers will be rejected. Bidders for a short list can expect to be notified on or about November 1, 2012. There will begin negotiations of final offers. Final negotiation and the signing of offers will occur if the negotiations are successful.

4.2. NOTICE OF INTENT TO SUBMIT PROPOSAL

A Notice of Intent to Submit a Proposal is requested from all prospective Bidders. This notice includes a Confidentiality Agreement. This will be Form 1 in the Required Forms and should be returned to the IPM Official Contact as listed in Section 1.4. This form is due to the IPM at The Brattle Group offices by no later than by 4PM PDT on July 3, 2012. In addition to postal mail, fax, and email are sufficient as means to return the Notice of Intent to Submit Proposal. Potential Bidders should make their best effort to provide accurate information about their planned Proposal; however, Bidders will not be bound by the information provided in the completed Form 1, Notice of Intent to Submit Proposal.

4.3. Deadline and Method Proposal Submission

Proposals are due to the IPM no later than 4PM PDT on August 30, 2012. Proposals are to be submitted by mail, e-mail, fax, or hand delivery. Faxed or e-mailed proposals must be followed up by mail with a signed original which must be received no later than 4PM PDT on September 5, 2012. All correspondence should be directed to the IPM, as indicated in Section 1.4 of this RFP document.

5. PROPOSAL CONTENT

A proposal should contain responses on all of the Required Forms, which will be provided in the website on June 15, 2012. The Forms will encourage Bidders to provide additional information or other supporting documentation to provide a complete description of the proposal. The Brattle Group will receive suggestions on how the Forms can be enhanced to allow more complete descriptions of the Bids and, at the discretion of EKPC, use those suggestions to finalize the Forms on July 10, 2012. EKPC retains the right to combine any Bid with any other Bid to determine a mix of resources that will provide a total economical and reliable resource package.

The Required Forms will deal with the following issues:

- Conditions on the Firmness of the Offers
- General Project Characteristics
- Development Status and Site Description, which describes three EKPC sites that will be offered for Facility Ownership / Purchase and Sale Agreement
- Capacity and Energy Profile
- Technical Description and Data by Resource Type
- Description of Pricing Methodology
- Pricing Information
- Transmission and Interconnection
- Financing and Credit Arrangements
- References
- Project Team
- EEI Master Purchase Power and Sale Agreement
- Power Purchase Agreement for the RFP, and the relationship to the EEI Master Agreement
- Purchase and Sales Agreement for the Facility Ownership

EKPC will provide the Required Forms on the website on June 15, 2012. On July 10, 2012, EKPC will provide final updates to the Required Forms.

6. PROPOSAL EVALUATION

6.1. Screening

All proposals will be evaluated for completeness and technical viability as a part of initial screening. Non-competitive bids will be eliminated based on this preliminary analysis.

6.2. Evaluation

EKPC and The Brattle Group will specifically take into account the price, type and location of project, reliability, dispatchability, transmission availability, financial stability, and any other factor which relates to the suitability of the proposed project for meeting EKPC's power supply needs. EKPC reserves the right to consider any and all aspects of any bid in its evaluation as well.

6.3 Financial Stability and Performance Guarantees

Financial stability of the Bidder, demonstrated ability to fulfill its contractual obligations and historical project and contract performance are of utmost importance to EKPC and will be an integral part of EKPC's evaluation process. EKPC requires secure and reliable physical delivery of the capacity and associated energy corresponding to all PPAs. A performance bond, or some other form of security acceptable to EKPC, will be required to ensure the consistency and reliability of the physical delivery of energy and capacity.

For equipment and/or erection contracts, successful Bidders shall secure, upon contract award, performance bond(s) to provide financial assurance that the project will meet schedule and proposed performance targets. EKPC reserves the right to determine, in its sole judgment, the sufficiency of any performance bond (or other form of security) proposed by Bidder.

The Bidder should discuss in detail the type and amount of proposed credit enhancements or other means proposed to guarantee performance under any contract that might result from this RFP. This discussion should identify the entity providing such performance security and provide all relevant terms of such security mechanism. Bidder must provide audited financial statements from the previous three years in order to demonstrate its financial viability. Such financial information shall also be provided for any entity which would provide a performance bond or other form of security.

Bidders proposing "greenfield" sites or new generation at one of EKPC's 3 suggested locations must provide a description of the Bidders' ability to execute such projects as demonstrated by previously applicable experience and examples of operating facilities caused to be designed, permitted, constructed, tested and achieving successful commercial operation within a time frame typical for such type of project. Other means of satisfying EKPC's concerns regarding the Bidders expertise and experience may be considered but will be at EKPC's sole discretion in determining the Bidders qualifications and acceptance or rejection.

Failure by Bidders to not address the requirements herein may result in rejection of the Bid(s).

6.4. CONFIDENTIALITY

Form 1 Notice of Intent to Submit a Proposal is part of the Required Forms and will contain a Confidentiality Agreement. The Bidder must return a signed Required Form including the Confidentiality Agreement on July 3, 2012, as discussed above Section 4.2.

EKPC will not disclose any information contained in the Bidder's proposal that is marked "Confidential" to another party unless such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction. As a regulated utility and electric cooperative, EKPC may be required to release proposal information to various government agencies and/or others as part of a regulatory review or legal proceeding. EKPC also reserves the right to disclose proposals to any EKPC consultant(s) for the purpose of assisting in evaluating proposals. In the event EKPC is required to submit copies of proposals to the Kentucky Public Service Commission (PSC) or other governmental or regulatory agency, EKPC will attempt to file such information labeled as "Confidential" on a confidential basis. Designating specific information as confidential, rather than the entire proposal, may facilitate such efforts. However, EKPC cannot guarantee that such information will be deemed confidential by the agency or court the information is filed with.

By submitting a proposal to EKPC under this RFP, Bidder certifies that it has not divulged, discussed, or compared its proposal with other bidders and has not colluded whatsoever with any other bidder or parties with respect to this proposal.

6.5. ACCEPTANCE OF PROPOSALS

EKPC reserves the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. EKPC also reserves the right to request further information, as necessary, to complete its evaluation of the proposals received, and to negotiate with Bidders selected for the short list, prior to any selection of any winning proposals. Bidders who submit proposals do so without recourse against EKPC for either rejection by EKPC or failure to execute an agreement for purchase of capacity and/or energy for any reason. EKPC will not reimburse any Bidders for any cost incurred in the preparation or submission of a proposal and/or any subsequent negotiations regarding a proposal. All hard copies of proposals once submitted will become the property of EKPC.

6.6. Short List Development

EKPC will develop a short list of potential proposals based on the benefit to EKPC's members. EKPC will then refine its analyses and develop its final decision. Acceptance of final bids will most likely be subject to approval by the Kentucky Public Service Commission, permitting agencies and potentially the Rural Utilities Service or other lenders. All respondents to the PPA Bid options must keep the terms of their bids firm and in effect until October 28, 2012, after which the Bidders can refresh the Bids if EKPC wants to put the Bidder on the Short List.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	CASE NO. 2013-00259

EXHIBIT 8

DIRECT TESTIMONY OF JAMES READ

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 21, 2013

I. Introduction

Q. Please state your name, position, and business address.

A. My name is James Read. I am a Principal with The Brattle Group. My office is located at 44 Brattle Street in Cambridge, Massachusetts.

Q. What is the purpose of your testimony?

A. I have been asked by the East Kentucky Power Cooperative to describe the 2012 Request for Proposal ("RFP") process, The Brattle Group's role in that process, and a recommended course of action.

Q. Please summarize your education and professional experience.

A. I have been consulting in the areas of energy and financial economics for over 30 years. My consulting practice has focused on the electric power and natural gas industries, including the valuation of energy resources and contracts, investment decision making, portfolio risk management, market analysis and modeling, energy trading, and supply procurement. I have worked for many years with the Electric Power Research Institute (EPRI) to apply modern financial economics to decision making in the electric power industry, to develop tools and methods for valuation and risk management, and to teach principles and methods of value and risk to industry participants. I hold a bachelor's degree in economics from Princeton University and a master's degree in finance from the Sloan School of Management at the Massachusetts of Technology.

Q. What was The Brattle Group's role in the 2012 RFP?

A. The Brattle Group (Brattle) was engaged to assist EKPC develop and market the RFP, screen proposals, select a short list, and report on a recommended course of action. This was a collaborative effort in which Brattle leveraged EKPC's Power Supply planning staff, analytical resources, and data.

Q. What is the role of an independent procurement manager ("IPM")?

A. The issuer of an RFP may engage an IPM for various reasons. One reason is that the issuer anticipates that an affiliate will participate in the RFP process as a bidder, so it engages an IPM to assure that the process is fair, open, and non-discriminatory. In this case, EKPC expected to submit one or more "self-build" option(s) in response to the 2012 RFP.

Q. Can you describe the Brattle Group's experience serving as an IPM for other utilities?

A. The Brattle Group has served as the independent procurement manager for purchases or sales of long-term energy, renewable power, and electric power transmission rights. These include a recent RFP process for Northern Illinois Municipal Power Agency to solicit offers for a power purchase agreement or outright sale of an entitlement share of a coal-fired power plant; several auction processes for First Energy to procure solar renewable energy credits (subject to approval by the Pennsylvania Public Utility Commission); and open season processes for the sale of transmission rights between PJM and the New York ISO (subject to approval by the Federal Energy Regulatory Commission).

II. The 2012 Request for Proposals

Q. What was your personal role in conducting EKPC's RFP?

A. I was the project manager at The Brattle Group for this engagement.

Q. Who else at the Brattle Group was involved in conducting EKPC's RFP?

A. In addition to me, two other principals at The Brattle Group, Joseph Wharton and James Reitzes, were involved in the project. We were assisted by several research analysts and administrative assistants.

Q. Please describe the process of preparing EKPC's RFP?

A. Brattle and EKPC began the engagement in May with a meeting at EKPC's offices in Winchester, Kentucky. The principal topics at this meeting were the goals and timetable for the RFP, the types of supply options EKPC would be willing to consider, the creation of a web site to serve as the locus for the RFP process, and the news that EKPC expected to be integrated into the PJM Interconnection RTO prior to the target October 2015 in-service date.

Q. How much generation did EKPC seek to acquire through the RFP?

A. EKPC sought to obtain up to 300 megawatts (MW) of additional generation through the RFP.

Q. What types of power supply options was EKPC willing to consider?

A. EKPC was willing to consider proposals to purchase new or existing power plants, to enter into intermediate-term or long-term power supply contracts, and to purchase power from renewable or conventional resources. EKPC identified a target start date of October 2015 for new resources but said it would consider proposals that specified earlier or later dates. The only strict constraints that EKPC imposed on the supply proposals were that they (a) specify a term of at least five years and (b) specify no less than 50 MW if for power from conventional generation resources and no less than 5 MW if for power from renewable generation sources.

Q. How did The Brattle Group go about marketing the RFP?

A. EKPC and Brattle assembled a list of potentially interested parties. Among others this included a list of firms that had expressed interest after EKPC announced its intention to issue an RFP in a press release on April 23, 2012. Brattle simultaneously built a web site through which interested parties could obtain the RFP documents, forms, and calendar, register to receive RFP updates, submit questions ("ask the manager"), obtain required forms, and submit their proposals. The web site was also used to post answers to questions thought to be of general interest ("frequently asked questions").

Q. How did The Brattle Group, as IPM, answer questions that were posed by prospective bidders?

A. We posted answers to questions posed by prospective bidders on the RFP web site.

Q. Did The Brattle Group conduct any informational meetings for prospective bidders prior to the deadline for submitting bids?

A. Yes, Brattle conducted an informational Webinar for potential bidders on the 27th of June.

Q. Please summarize the responses to the RFP.

A. EKPC received a large and diverse set of proposals in response to the RFP. These included proposals for new natural-gas fired power plants, some at existing EKPC sites, others outside of EKPC; proposals to sell EKPC existing gas or coal-fired plants, or ownership shares thereof; natural gas tolling agreements, with rights to the associated capacity as well as energy; power purchase agreements with contract price terms linked to the owner's operating costs ("cost-based PPAs"); energy-only contracts for "block" products, with liquidated damages provisions; capacity-only contracts; PPAs for power from renewable energy resources, including wind, solar, biomass, landfill gas, and waste; and proposals for energy from coal waste and mine mouth methane.

Q. Did EKPC submit any self-build proposals?

A. Yes. In addition to the proposals received from third parties, EKPC's Power Production Engineering & Construction (PPE&C) group submitted several proposals in response to the RFP.

Q. Did you have any contact with anyone involved with the preparation of EKPC's self-build proposals regarding the nature or substance of any of the self-build proposals prior to the evaluation phase of the RFP process?

A. No. The only communications Brattle had with EKPC's PPE&C group prior to the evaluation phase were procedural in nature.

III. Evaluation of Proposals

Q. Once you received the bids in August, what process did you use to evaluate them?

A. Prior to evaluating proposals, The Brattle Group verified that they were from qualified bidders (by virtue of having submitted a Notice of Intent to Bid) and that the bidders had submitted the other required forms.

Q. Were any bids disqualified?

A. No. Several firms initiated but did not complete the notification process. None of those firms submitted a bid.

Q. How did you go about evaluating proposals from qualified bidders?

A. Proposals were evaluated under the assumption that EKPC would be integrated into PJM by the beginning of the planning period. In fact, EKPC is already integrated into PJM. As a PJM member, EKPC's load obligations and power supply portfolio are effectively separated—EKPC schedules its load with PJM and bids its generation into PJM on a daily basis. EKPC pays PJM for the energy, capacity, and ancillary services its owner-members consume. EKPC receives payments from PJM for the energy, capacity, and ancillary services it produces.

Q. Why is EKPC's integration into PJM relevant to the evaluation of proposals received in response to the RFP?

A. Prior to its integration into PJM, EKPC's ability to buy power from and sell power to third parties was very limited. As a result, it had to plan to meet the power supply needs of its owner-members largely from its own generation resources. Now, in contrast, PJM is both the supplier to EKPC's owner-members and the market for the production of EKPC's generation fleet. Therefore, constructing or acquiring additional generation resources is an option for EKPC, not a requirement.

Q. What criteria did you apply to evaluate proposals?

A. The principal criterion we applied to evaluate power supply proposals was net present value.

Q. What do you mean by "net present value"?

A. The net present value (NPV) of a power supply resource is equal to the difference between (a) the present value of the energy and capacity it is expected to provide and (b) the present value of the costs that EKPC would incur to obtain that energy and capacity. It is the proposal's *value added.* As I said, EKPC pays PJM for the energy and capacity its members consume and PJM pays EKPC for the energy and capacity its generation resources produce. Therefore, one can also think of the net present value of a power supply proposal as the expected *reduction* in net power supply costs to EKPC owner-members conditional on the proposal's acceptance.

Q. Did your evaluation take the size and duration of proposals into account?

A. Yes. In addition to calculating NPVs, we calculated NPVs normalized for the size and duration of the proposals, that is, the NPV per megawatt-year.

Q. Did your analysis of facility purchase and retrofit proposals take the required capital investments into account?

A. Yes. Like fuel and operating and maintenance costs, the purchase prices and investments associated with proposed facility purchases and retrofits were deducted from the present value of the energy and capacity a proposal was projected to provide. In addition, we calculated the benefit-cost ratio for facility purchase and retrofit proposals. The benefit-cost ratio is the ratio of the net present value of the proposal to the purchase price or required capital investment.

Q. Did you take factors other than NPV, NPV per megawatt-year, and benefit-cost ratio into account in your consideration of proposals?

A. Yes. EKPC has certain strategic objectives that could have a bearing on the choice of power supply options. One of EKPC's strategic objectives is to rebuild its equity-to-assets ratio. Another strategic objective is to diversify its supply mix.

Q. What is EKPC's current supply mix?

A. EKPC is a predominantly coal-fired electric utility—about two thirds of its generation capacity is coal-fired and one third is natural gas-fired. EKPC also owns several landfill gas facilities and purchases hydro power from the Southeastern Power Administration. As a result, over 80 percent of its energy supply is coal-based. Due largely to the decline in natural gas prices, coal-fired generation has become less competitive and gas-fired generation more competitive, a consequence of which is that the power market as a whole has a substantial and increasing amount of natural gas in the generation mix. Also, over the long term, gas-fired generation is less exposed than coal to the possibility that carbon emissions will be priced or taxed. Therefore, shifting the EKPC supply portfolio towards gas-fired generation would be desirable from the standpoint of hedging its members' exposures to market risks.

Q. Did you take other factors into account—factors other than NPV and EKPC's strategic objectives?

A. Yes. As I said earlier, EKPC received a diverse set of proposals in response to the RFP. The proposals included facility acquisitions, which would entail substantial up-front investments, as well as power purchase agreements, which do not. Some were for renewable generation resources, others for conventional resources.

Some were for dispatchable resources, some for baseload resources, and others for intermittent resources. The heat (energy conversion) rates of the proposed dispatchable resources vary too. Therefore, comparing the proposals strictly on the basis of NPVs—even when normalized for size and duration—would amount to comparing apples to oranges.

Q. How did you take the diversity of proposals into account?

A. We compared proposals with similar characteristics. Specifically, we identified several categories of proposals and assigned each proposal to one of the categories. The categories were:

- PPAs for power from conventional (or unspecified) energy resources—most of the power purchase agreements offered are structured as tolling agreements or call options or provide some degree of dispatch flexibility. The energy output will tend to be greater under contracts with low heat (i.e., energy conversion) rates than those with high heat rates. Proposals for high heat rate resources were put in a separate category from proposals with low heat rates.
- Ownership of generation resources—as distinct from the contractual obligations of a PPA—would entail an up-front investment of funds and thus associated financing requirements. Ownership would also entail management responsibilities (e.g., operation and maintenance).
- PPAs for power from solar and wind generation resources are intermittent supplies—when available, they would provide a flow of energy subject to ambient weather conditions (e.g., wind speed and sunshine).

- PPAs for power from other renewable energy resources (landfill gas, waste, biomass) have the character of baseload resources—they typically would produce energy approximately equally over the diurnal and seasonal cycles.
- Self-build proposals were a separate category. The self-build options are qualitatively distinct from the other proposals EKPC is considering. If EKPC were to enter into a contract with a third party, it would be able to negotiate performance provisions to protect itself in the event of a cost overrun, delay, etc. If EKPC chooses a self-build option, it will not have the ability to obtain comparable assurances.

Q. Do these categories capture all of the relevant distinctions among the power supply proposals?

A. Even within categories the proposals vary in terms of, for example, fuel type, contract duration, heat rate, and new build vs. retrofit. However, we were aware of these differences when considering the proposals.

Q. How did you proceed?

A. We created a short list of bidders by selecting the most attractive proposal in each category. The project team then held further discussions with each of the short list bidders, either by telephone or in person, to review and clarify proposal terms.

III. Conclusions

Q. What did your analysis of the proposals conclude?

A. We concluded that one of the self-build proposals, a proposal to retrofit Cooper Unit No. 1, was the most attractive of those on the short list. We also initiated negotiations with certain other bidders on the short list.

Q. What was attractive about the proposal to retrofit Cooper Unit No. 1?

A. The Cooper 1 retrofit would in effect "piggyback" on the retrofit of Cooper Unit No. 2, which was completed in 2012. It would return 116 MW of existing generation to service for an investment of $15 million. This is roughly $125/kW of capacity versus figures in the range of $600/kW to over $1,000/kW for new generation.

Q. Is it your professional opinion that the Cooper 1 retrofit is the single best proposal from among those submitted to EKPC through the RFP process?

A. Yes, based on my understanding of EKPC's objectives, constraints, and opportunities, the retrofit of Cooper Unit No. 1 is the best of the proposals.

Q. Are you continuing to be involved in EKPC's efforts to fulfill the remaining additional capacity anticipated to be chosen through the RFP?

A. Yes, I am continuing to work with EKPC as it considers the acquisition of additional resources.

Q. Can you provide a copy of your written recommendation for the Commission's review?

A. Yes. It is attached as Exhibit 1 to EKPC's Application.

Q. Does that conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)))))))))	**CASE NO. 2013-00259**

<u>AFFIDAVIT</u>

COMMONWEALTH OF MASSACHUSETTS)
)
COUNTY OF MIDDLESEX)

James Read, 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 31st day of July, 2013.

Jennifer M. Ossen
Notary Public

Commission Expires: Feb 11, 2016

JENNIFER M. OSSEN
Notary Public
Commonwealth of Massachusetts
My Commission Expires Feb. 11, 2016

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)))))))))	**CASE NO. 2013-00259**

EXHIBIT 9

DIRECT TESTIMONY OF BLOCK ANDREWS

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 21, 2013

Q. **Please state your name and title.**

A. Block Andrews, P.E. I am a Strategic Environmental Solutions Director at Burns & McDonnell.

Q. **Please provide an overview of your education and professional background.**

A. I have a B.S. in Mechanical Engineering from the University of Denver, 1984 and a M.S. in Atmospheric Sciences from the University of Illinois, 1989. I have worked for Lockheed Martin as a Systems Engineer for 3 years on the MX and ICBM missile systems. I have worked as Environmental Director for Aquila for 7 years with a staff of 13 people. I have worked for Burns & McDonnell for 18 years in a variety of roles including Section Chief of Air & Noise and now in my current role as Strategic Environmental Solutions Director.

Q. **Please describe your job duties at Burns & McDonnell.**

A. I work with utilities to help answer the question of what to do with their coal plants. This can include plant shutdown, retrofit with pollution controls, repowering, and fuel switching. My role involves several components:

1. Understanding of existing and proposed environmental regulatory requirements

2. Understanding of an existing plant's environmental status (current and expected fuel, emissions, pollution control equipment, waste handling, water balance)

3. Understanding of available controls for environmental compliance as well as potential capital and O&M costs for future environmental compliance

4. Condition assessment. An evaluation of potential future major maintenance expenses

5. Resource Planning. An evaluation of a utility's generation options.

I have been Project Manager for these types of projects in some cases and in other cases, I have been responsible for the first 3 components of the study.

Q. **What is the purpose of your testimony in this case?**

A. I will provide testimony on the process used to determine environmental compliance options for Cooper 1, the development of a recommended compliance option and the implementation strategy to meet regulatory timeframes.

Q. **Please describe the background associated with Burns & McDonnell's being hired by EKPC for this Project.**

A. Burns & McDonnell performed detailed design for EKPC's Cooper 2 Retrofit Air Pollution Project. That project included the installation of several pieces of air quality control system ("AQCS") equipment on Cooper 2, including a dry flue gas desulfurization ("DFGD") system, a selective catalytic reduction ("SCR") system and a pulse jet fabric filter ("PJFF"). Burns & McDonnell's successful execution on the Cooper 2 project along with our experience in the industry was the reason why EKPC hired us for this Project.

Q. **Describe Burns and McDonnell's participation in the Request for Proposal ("RFP") process initiated by EKPC in 2012 to identify the best resource, or mix of resources, to satisfy EKPC's anticipated capacity requirements?**

A. Burns & McDonnell was hired to identify potential air pollution control alternatives at EKPC's Cooper 1 that would allow the unit to continue operation while complying with future emissions regulations including Mercury and Air Toxics Standards ("MATS") and Best Available Retrofit Technology ("BART"). As part of this effort, Burns & McDonnell also assisted in the creation of a new generation unit self-build proposal for each identified alternative which were submitted in response to the RFP.

Q. **What was the scope of Burns & McDonnell's work for this Project?**

A. Burns & McDonnell's scope for this project included the initial evaluation of alternatives and the development of a detailed Project Development Report ("PDR") for the selected alternative. The PDR identified the scope, cost and schedule for implementation of the Project along with the assumptions that were used. A true and correct copy of the PDR is attached and incorporated into my testimony as Exhibit BA-1.

Q. **What were Burns & McDonnell's objectives for the Project study?**

A. Initially, Burns & McDonnell reviewed the upcoming environmental regulations and identified compliance options. For these compliance options, Burns & McDonnell developed indicative capital and O & M costs. After discussion with EKPC, one option was chosen upon which to perform further detailed studies. This option is ducting Cooper 1 exhaust through the existing Cooper 2 DFGD/PJFF system. Additional details from equipment vendors were obtained to determine more detailed cost and performance parameters.

Q. **Please provide an overview of the Project including a full description of the proposed location of the new construction, including a description of the manner in which it will be constructed.**

A. The Project includes the addition of ductwork and controls to allow the exhaust gas from Cooper 1 to be routed to the Unit 2 DFGD/PJFF system. The new construction will be within the boundaries of the existing plant footprint. The construction will include the installation of new foundations, structural steel, ductwork, dampers and modifications to the existing air quality control equipment. It will be constructed using industry standard techniques very similar to the recently completed project on Cooper 2.

Q. **Does the Project constitute new construction for EKPC?**

A. No. The Cooper 1 is an existing resource for EKPC and thus the Project is not "new construction." Accordingly, the Project will not result in any competition with the resources of any other public utilities, corporations or other persons.

Q. **What factors or information led to the consideration of combining the exhaust gases of Cooper 1 and Cooper 2?**

A. Combining the exhaust gases for Cooper 1 and Unit 2 was considered for two reasons. First, the DFGD/PJFF system on Cooper 2 is performing well and is capable of controlling additional exhaust gas flow from Unit 1. Second, combining the Cooper 1 and 2 exhaust gases will allow Unit 1 to achieve compliance with MATS and BART requirements.

Q. **Did Burns & McDonnell perform any testing or modeling to determine if it was feasible to combine the exhaust gases from the two units?**

A. Yes, with assistance from the Cooper 2 DFGD/PJFF vendor, Andritz.

Q. **Could you please describe in detail the testing or modeling performed and the results?**

A. At Burns & McDonnell's request, Andritz conducted a detailed analysis of the capabilities for the existing Cooper 2 DFGD/PJFF to accept additional exhaust gas from Unit 1. This detailed analysis included constructing a physical flow model of the system and also utilizing Andritz proprietary design software to evaluate the capabilities. The results of this analysis determined that the DFGD/PJFF was capable of treating additional exhaust gas from Cooper 1 in addition to the exhaust gas from Unit 2. However, the analysis was not able to determine the total amount of exhaust gas from Unit 1 that could be treated definitively. In order to further evaluate the potential of the Cooper 2 DFGD/PJFF, Burns & McDonnell and Andritz conducted field testing. This testing consisted of utilizing the existing bypass system on the Cooper 2 DFGD/PJFF to simulate the higher exhaust flow from both Cooper 1 and Cooper 2. The results of this testing demonstrated that the existing Cooper 2 DFGD/PJFF was capable of treating all the exhaust gas from both units.

Q. **Does combining the Unit 1 exhaust gas flow with the Unit 2 exhaust gas flow present any new operational challenges for EKPC?**

A. Yes, combining the two exhaust gas streams will require more operational coordination between the units than is currently required. Also, the new configuration will require low load restrictions on Unit 1 when it is operating alone.

Q. **Is there any reason to believe that with proper training of shift supervisors and control room operators EKPC cannot adequately address these operational challenges?**

A. The combined operation of the units will not significantly increase the complexity of the controls utilized by the plant. The operational changes can be adequately addressed through changes to the plant's control system and operator training.

Q. **Please discuss whether the Project will significantly change the current use of such things as air quality control chemicals, water and fuel, and whether there will be any increased noise or substantial alterations in the overall aesthetics of the existing Cooper plant.**

A. The Project will result in additional hydrated lime and water usage to treat the exhaust gas from Unit 1. This Project will also result in additional waste ash production from the facility which will increase the number of haul trucks going to the on-site landfill. This Project is not expected to change the noise or overall aesthetics of the existing Cooper plant.

Q. **Was it important to evaluate and estimate the emissions and performance of the Cooper plant once the Project is completed?**

A. Yes. Burns & McDonnell has worked with the existing Unit 2 DFGD/PJFF vendor, Andritz, on this Project. Andritz is willing to guarantee emissions and performance levels that will meet MATS and BART compliance limits.

Q. **Why was it important?**

A. MATS and the BART determination in the Kentucky Regional Haze State Implementation Plan will require Cooper 1 to meet stringent acid gas, filterable particulate matter, and mercury emissions limits and will require DFGD/PJFF controls to meet the limits. The purpose of the Project is to allow Cooper 1 to comply with these regulatory requirements. Further, to compete in PJM, the additional controls need to be cost effective as well as compliant with new environmental regulations.

Q. **Please describe the evaluations which Burns & McDonnell performed to arrive at emissions and performance estimates for the Cooper plant.**

A. Burns & McDonnell reviewed the existing emissions data and existing air pollution controls. This data was compared to the required emissions under MATS and BART. It was determined that emission reductions would be required to meet the upcoming MATS and BART regulations. Several compliance options were developed based on expected performance of new or modified air pollution controls. The expected performance was obtained from equipment vendors. For the ESP Unit 1 modifications, Burns & McDonnell contacted the legacy company of the original ESP ("Alstom"). For the ducting of Unit 1 exhaust into the Unit 2 DFGD/PJFF option, we contacted the Unit 2 DFGD/PJFF vendor, Andritz, to obtain cost and performance data. As the study progressed, the preferred DFGD/PJFF compliance option was further evaluated with additional studies and information provided to Andritz so that they could provide emission and performance guarantees.

Q. **What did Burns & McDonnell's study determine were the likely emissions and performance estimates?**

A. Burns & McDonnell provided Andritz with a list of information to determine if the existing Unit 2 DFGD/PJFF system could operate under a variety of operating scenarios. These scenarios ranged from a low-flow case of Unit 1 operating at 100 MW load to a case where both Unit 1 and Unit 2 were operating at full load.

Based on these scenarios, Andritz used physical and computational fluidized modeling to determine that the scenarios given could meet the specified emissions rate with some modifications to the current DFGD/PJFF system. Andritz will provide emission and performance guarantees for these operational scenarios.

Q. **Once the Project is completed and commercial operations have commenced what will be the estimated respective generating capacities for Cooper 1 and Cooper 2?**

A. The gross capacity will not change; however, the net capacity could be slightly impacted (less than 1 percent de-rate) due to the additional backpressure.

Q. **Once completed, will the Project have a significant impact on EKPC's current Title V air permit?**

A. EKPC submitted an application to the Kentucky Division of Air Quality ("DAQ") for a significant revision to the Cooper Title V permit to implement the Cooper 1 re-duct Project on March 25, 2013. The application adds the DFGD/PJFF system as a control technology for Cooper 1 and incorporates certain MATS and BART requirements. The application also identifies the additional truck traffic resulting from the additional pebble lime product needed for the DFGD system and the additional ash produced. However, the increase in truck traffic emissions are more than offset by the improved particulate matter and acid gas emissions reductions that will be achieved by ducting Unit 1's exhaust through the Unit 2 DFGD/PJFF.

Q. **What has been determined to be the most advantageous Project execution approach?**

A. Multiple Contracting Approach. This approach utilizes multiple prime contractors having unique expertise in certain areas executing the installation of equipment for the project. It will also be the responsibility of these prime contractors to procure commodities and materials for use in their discreet portions of the Project. However, EKPC will still be responsible to purchase the major equipment and all engineered balance of plant equipment. The principal advantage to this approach is two-fold: first, it matches certain difficult and essential construction activities with contractors possessing demonstrated experience and success with that type of construction and materials procurement; and second, because of this expertise that portion of the Project should be more economical than if one general prime contractor was required to subcontract that same activity.

Q. **Describe the overall Project schedule including the anticipated commercial operation date and the important constituents necessary to meet that date.**

A. There are five portions of the schedule:

1. Upfront approvals,
2. Detailed Engineering Design,
3. Procurement,
4. Construction and
5. Startup/Commissioning.

Construction cannot begin until the upfront regulatory and permitting approvals are obtained. The upfront approvals include the CPCN, Cooper Title V permit revision to incorporate this Project, and approval by the United States

Environmental Protection Agency ("EPA") of a change in the continuous emissions monitoring configuration required under the New Source Review consent decree between EKPC and the United States of America. The schedule assumes approval of these items by May 2014. EKPC submitted an application for a Title V permit revision to DAQ on March 25, 2013. EKPC also submitted a request for approval of the proposed monitoring configuration to EPA on June 4, 2013. After upfront approvals, the Notice to Proceed for Engineering can begin the detailed design. As soon as September 2014, procurement activities can begin and will continue for the next 17 months (November 2015). The Project will be staged for some construction activities to begin in April 2015 and continue through December 2015. During a scheduled unit outage, the new equipment will be tied into the system. From January 2016 through March 2016, the system will have startup, shakedown and commissioning prior to the expected MATS compliance date of April 16, 2016. On July 24, 2013, DAQ granted EKPC's request for a one-year extension to the April 16, 2015 MATS initial compliance date to allow the Project to proceed on schedule.

This schedule assumes that all upfront approvals are obtained by May 2014. If these approvals are not obtained, a re-evaluation of the schedule will be required.

Q. **Is the commercial operation date tied to the need by EKPC to comply with certain environmental regulatory air quality standards?**

A. Yes, MATS requires existing sources to achieve initial compliance with the rule by April 16, 2015. However, section 112(i)(3)(B) of the Clean Air Act allows existing sources to obtain a one year compliance extension from the state permitting authority for the installation of controls. As noted, EKPC received this one year compliance extension on July 24, 2013.

Q. **What has Burns & McDonnell estimated the Project's capital cost to be?**

A. Our estimate for the Project is $15,000,000. This cost will be further refined once specific vendor quotations are received.

Q. **Please provide the principal assumptions used in the development of this estimate.**

A. The principal assumption used in the development of the estimate was that the Cooper 2 DFGD is capable of treating the flue gas from both Unit 1 and 2. There was extensive analysis and testing performed to confirm the capabilities of the existing DFGD system in order to support this assumption as mentioned previously. The other assumptions that were used for the estimate are as follows:

1. Project executed based on a multiple prime contracting approach;
2. Equipment costs based on budgetary proposals;
3. Construction commodity and indirect costs based on recent pricing on similar projects;
4. Labor rates and productivity based on recent experience on the Cooper 2 project;
5. Project completion in Spring of 2016; and
6. Union labor working 10 hours per day, 5 days per week

Q. **Please discuss Cooper 1's estimated annual Operations and Maintenance ("O&M") costs once the Project has commenced commercial operations.**

A. It is estimated that there will be an additional $4.45 / MWh variable O&M cost associated with the Project. This includes additional costs for reagent and waste disposal associated with treating the Unit 1 exhaust gas. There is not expected to be any additional labor expense for maintenance of equipment.

Q. Can EKPC expect to see greater overall efficiencies in O&M costs for the entire plant (Cooper 1 and 2) once the Project has commenced commercial operations?

A. This Project will not have a significant impact on the efficiencies in O&M costs for the entire plant.

Q. Please outline for the Commission what benefits EKPC will ultimately receive for its expenditure of approximately $15,000,000 to construct this Project.

A. The $15,000,000 Project will allow Cooper 1 to continue to operate beyond 2015 in compliance with environmental regulations.

Q. In your opinion, do the benefits of this Project to EKPC and its customers justify the amendment of EKPC's Environmental Compliance Plan to include it?

A. Yes.

Q. In your opinion, will the Project, once it has commenced commercial operations, significantly assist EKPC in complying with federal, state and/or local environmental regulatory air quality standards?

A. Yes.

Q. Would you like to summarize your testimony?

A. Burns & McDonnell has performed a regulatory analysis of the required air quality compliance limits and determined that additional reductions in mercury, filterable particulate matter, and acid gases will be required for Cooper 1 to operate beyond 2015 in compliance with MATS and BART requirements. Several air pollution control options were developed with assistance from air pollution control vendors. After consideration of each option's expected performance, reliability, and cost, Burns & McDonnell recommended that a detailed analysis of ducting Unit 1 exhaust into the existing Unit 2 DFGD/PJFF be conducted. The analysis determined that this option was not only feasible but the most reliable, cost effective air pollution control to meet MATS and BART requirements. Based on this analysis, EKPC's power production business unit determined to bid the Project into the RFP.

Q. Does that conclude your testimony?

A. Yes.

EXHIBITS

Document	Exhibit
Cooper 1 Project Development Report (March 2013)	1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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AFFIDAVIT

STATE OF Missouri)
)
COUNTY OF Jackson)

Block Andrews, 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.

Block Andrews

Subscribed and sworn before me on this 24th day of July, 2013.

Amy S Coleman
Notary Public

AMY S. COLEMAN
Notary Public-Notary Seal
STATE OF MISSOURI
Jackson County
My Commission Expires Oct. 2, 2015
Commission # 11444351

Burns & McDonnell
SINCE 1898

Cooper Unit 1 Duct Reroute Project Definition Report

EAST KENTUCKY POWER COOPERATIVE
A Touchstone Energy® Cooperative

East Kentucky Power Cooperative

March 2013

Cooper Unit 1 Duct Reroute Project Definition Report

prepared for

East Kentucky Power Cooperative
Winchester, Kentucky

March 2013

prepared by

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

INDEX AND CERTIFICATION

East Kentucky Power Cooperative
Cooper Unit 1 Duct Reroute
Project Definition Report

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CERTIFICATION

I hereby certify, as a Professional Engineer in the state of Kentucky, that the information in this 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.

STATE OF KENTUCKY
MICHAEL D. CLAUSEN
28759
LICENSED
PROFESSIONAL ENGINEER

Aug 1 2013 08:36 AM

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1.0 EXECUTIVE SUMMARY

East Kentucky Power Cooperative (EKPC) (Owner) recently installed a circulating dry scrubber (CDS) system at the John Sherman Cooper Power Station (Cooper) Unit 2. The CDS system includes a dry flue gas desulfurization (DFGD) system along with an integral pulse jet fabric filter (PJFF). This Project will combine the Cooper Unit 1 exhaust gas with the Cooper Unit 2 exhaust gas going into the CDS to achieve compliance with the Mercury and Air Toxics Standards (MATS) and Regional Haze State Implementation Plan particulate emission limitation and Best Available Retrofit Technology (BART) requirement for both Cooper Unit 1 and Unit 2. The Project consists of combining the exhaust gas from the Unit 1 induced draft (ID) fan with the Unit 2 exhaust gas prior to the CDS. Implementation of the Project will result in the CDS, the existing Unit 2 ID fan, and the CDS minimum flow recirculation damper being common components to Unit 1 and Unit 2.

EKPC and Burns & McDonnell have determined that the recently installed CDS has adequate capacity to control the exhaust gas from Cooper 1 and Cooper 2 to meet the 0.030 lb/MMBtu emissions rate for filterable PM. Currently the CDS is operating such that filterable PM emissions from Unit 2 are significantly better than the BART SIP PM limit of 0.030 lb/MMBtu. The CDS has demonstrated capacity to accept and adequately treat the additional gas flow from Unit 1, which will have already been subjected to control through the existing Unit 1 electrostatic precipitator.

The Owner has retained Burns & McDonnell (BMcD) to assist in developing the Project and providing preliminary scope, performance, schedule, and cost estimates. This report summarizes the Project definition and presents EKPC with information for use in evaluating the feasibility of the Project.

The Project will include new ductwork from the Unit 1 ID fan to the Unit 2 ductwork tie-in location, exhaust gas regulating and isolation dampers, upgraded control system, and new continuous emissions monitoring system (CEMS) equipment. The Project scope also includes foundations, support steel, access steel to support the new balance of plant (BOP) equipment, demolition of the existing stack division wall and sealing of the existing Unit 1 stack breaching. In addition to the new BOP equipment, the CDS equipment will be upgraded as necessary including incorporating a modified hydrated lime feed system to allow dual hydrator operation, and longer fabric filter bags and cages to support the increased gas flow through the CDS equipment. The Project is planned for a commercial operation date (COD) of April 2016.

1.1 Purpose

The purpose of this report is to provide the overall scope, schedule, performance and cost estimates of the Project based on the documents contained herein, and to provide general information to support the following activities:

1. Internal Approvals
2. Permitting
3. Kentucky Public Service Commission (PSC) Filings

1.2 General Design

The recommended configuration for the Project was developed jointly by the Owner and BMcD. The Project attributes include the following:

1. Ductwork from Unit 1 ID fan to Unit 2 tie-in location, including foundations and support steel.
2. One regulating and one isolation damper on Unit 1.
3. One regulating and one isolation damper on Unit 2.
4. CEMS equipment to support Consent Decree (CD) and permitted emissions compliance requirements as a result of the Project.
5. Controls and instrumentation integration to support common unit controls.
6. Modifications to the hydrated lime feed system, including dual hydrator operation.
7. Longer bags and cages for the CDS equipment.
8. Demolition of existing stack division wall.
9. Sealing of the existing Unit 1 stack breaching.

1.3 Project Execution Approach

Safety will be a primary focus for the Project. The Project estimate includes a full time safety professional on site during construction. In addition, lessons learned from the favorable safety performance achieved on the previous Cooper Unit 2 project will be implemented.

The selected contracting strategy for the Project is a multiple prime contract approach. This approach was selected based on EKPC's input and past experience with recent projects. Under this approach, engineered equipment will be procured directly by EKPC and turned over to the appropriate installation contractors. CDS equipment and associated design modifications will be procured from the supplier for the recently installed CDS for Unit 2 ("CDS Supplier"). The CDS Supplier has confirmed that the CDS will meet the emission limits for filterable PM, total PM, SO_2 removal efficiency or SO_2 emissions and mercury emissions from the combined flue gas out of Unit 1 and Unit 2 after introducing the Unit 1 exhaust gas into the CDS.

1.4 Schedule

BMcD has established a schedule based on receipt of a full notice to proceed (FNTP) to engineering in June of 2014 and a full release of major equipment purchase in September of 2014. This is followed closely by the associated construction, commissioning and testing activities. The overall schedule from FNTP through COD is 22 months, which is a typical duration for a project of this magnitude. EKPC has submitted the necessary Title V permit revision application for this project and has conservatively estimated permit issuance as of May 2014, after which FNTP will be issued. To allow the necessary 22 months for project completion, EKPC has no other option, but to request an extension of the MATS compliance date to April 15, 2016. Based on the estimated time necessary for all phases, Table 1-1 reflects the major milestones for the Project. This schedule is driven by the activities required to achieve EKPC approval, air permitting, CPCN approval, and construction contractor awards. Failure to meet the June 2014 FNTP date could lead to a delay of the 2016 project COD.

Table 1-1: Project Milestones

Permitting / Regulatory Activities	Date
CPCN Approval by PSC	December 2013
Receive Air Permit	May 2014
Engineering/Procurement	
Engineering FNTP	June 2014
Construction Period – 15 Months	
Start Construction	April 2015
Unit 1 & Unit 2 Outage	December 2015
Startup and Commissioning	January thru March 2016
Commercial Operation	April 2016

1.5 Capital Cost Estimate

The estimated capital cost for the Project is $14.95 million for the multiple prime contracting approach described in Section 1.3. The estimated cost includes escalation to reflect commercial operation in April of 2016, contractor contingency, contractor fees, and Owner's costs.

1.6 Design Data and Emissions

The Project is based on the design data and emissions values summarized in Section 4.0 of this report, and will allow both Unit 1 and Unit 2 to operate at their maximum continuous rated capacity while achieving emissions reduction necessary for compliance with MATS and BART. The Project will also allow Unit 1 to operate independently, with Unit 2 offline, and achieve emissions reductions on Unit 1 for compliance with MATS and BART.

2.0 INTRODUCTION

2.1 Background

In response to an RFP for generation issued by The Brattle Group on behalf of EKPC, EKPC engaged BMcD to assist in the development of a self-build proposal for combining the Unit 1 exhaust gas with the Unit 2 exhaust gas to utilize the CDS on Unit 2 to achieve MATS and BART compliance on Unit 1. The CDS system includes a dry flue gas desulfurization (DFGD) system along with an integral pulse jet fabric filter (PJFF). The proposed project would be installed at J.S. Cooper Station near Somerset, KY. The Cooper 2 CDS is capable of successfully controlling SO_2, Particulate Matter and Mercury to achieve MATS and BART compliance because of the robust nature of the CDS system design and the performance that it is currently achieving. Some upgrades will be made to the CDS system design to ensure that all necessary performance measures are met. New ductwork between Unit 1 and Unit 2 will be installed on the south side of the existing plant.

The project definition scope of work includes preparing the following major items:

1. Site Plan and General Arrangements
2. Capital and O&M Cost Estimates
3. Project Schedule

2.2 Objectives

The objectives of this study were to establish the preferred design parameters and technical basis of the major components of the Project, and to provide performance and cost estimates and an overall project schedule to support the following activities:

1. Internal Approvals
2. Permitting
3. PSC Filings

2.3 Limitations and Qualifications

Estimates and projections prepared by BMcD relating to schedule, performance, construction costs, and O&M costs are based on our experience, qualifications and judgment as a professional consultant in the air quality control system industry for coal-fired power plants. Since BMcD 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, BMcD does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by BMcD.

3.0 PROJECT DESCRIPTION

3.1 Overview

The Project for combining J.S. Cooper Station Unit 1 and Unit 2 exhaust gas for MATS and BART-SIP compliance on Unit 1 will consist of new ductwork from the Unit 1 ID fan to the Unit 2 ductwork tie-in location, exhaust gas regulating and isolation dampers, integration of the controls systems, and new CEMS equipment. The Project scope also includes foundations, support steel, access steel to support the new balance of plant (BOP) equipment, demolition of the existing stack division wall, and sealing of the existing Unit 1 stack breaching. In addition to the new BOP equipment, the CDS equipment will incorporate a modified hydrated lime feed system to allow dual hydrator operation, and longer fabric filter bags and cages to support the increased gas flow through the CDS equipment. The combined exhaust gas from the CDS equipment will be routed to the existing stack via the Unit 2 ID fan.

The Project will be designed to provide long-term reliable operation allowing both Unit 1 and Unit 2 to operate either simultaneously or independently up to their maximum unit load capacity or down to an approximate minimum load of 100 MW. Operation and maintenance philosophies will be consistent with electric utility standards, and all facilities will be designed to achieve a 20-year plant life. The Project will achieve MATS and BART compliance for Cooper Unit 1.

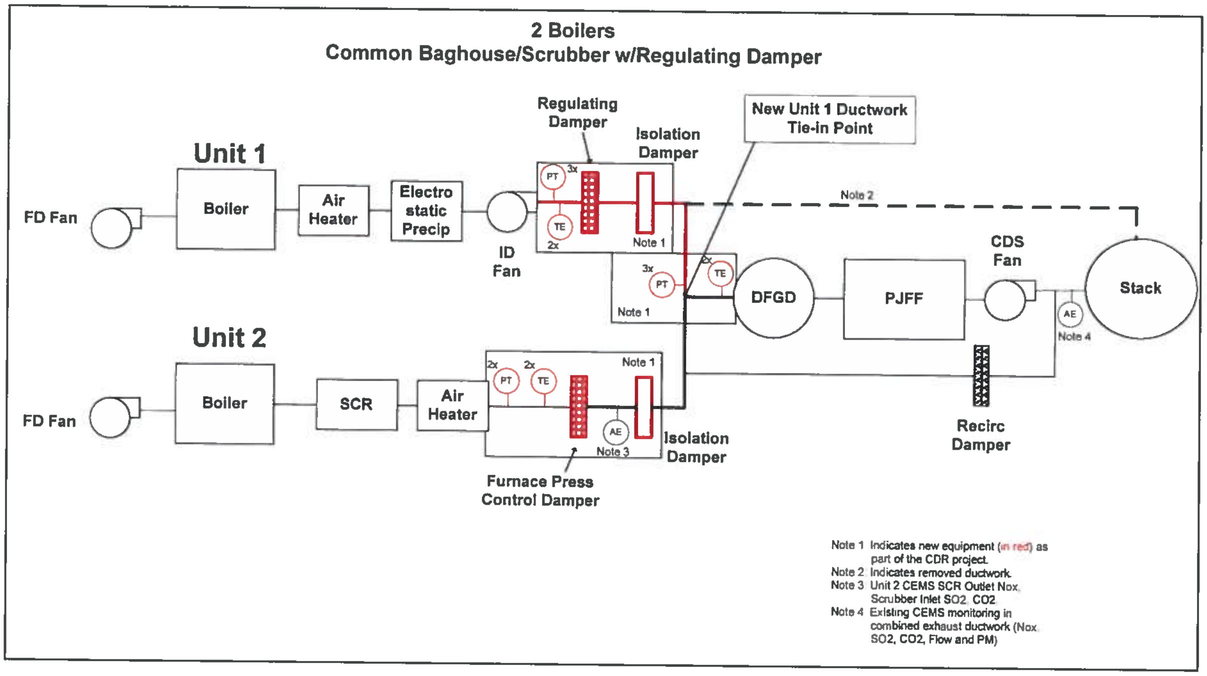
3.1.1 Operating and Control Philosophy

The Project for combining the Unit 1 exhaust gas flow with the Unit 2 exhaust gas flow to utilize the CDS on Unit 2 to achieve MATS and BART compliance on both Unit 1and Unit 2 requires a change in the boiler control strategy. This modification will require that the operation of both units be closely coordinated especially with respect to furnace pressure control since they will be tied together and will utilize common components. There will also be operating limitations placed on the units that don't currently exist. The most significant limitation will be when only Unit 1 is operating. During those periods, Unit 1's approximate minimum load will be 100 MW. However, this limit will not be in place when Unit 2 is operating simultaneously with Unit 1.

The following will discuss the requirements of the National Fire Protection Association (NFPA) 85 "Boiler and Combustion Systems Hazards Code" 2011 Edition code and the primary equipment operation for normal startup and shutdown and emergency trip conditions.

The proposed equipment configuration is shown below.

Figure 3-1: Project Equipment Configuration for Combined Unit 1 and Unit 2 CDS



As part of the Project several control strategy changes will be required. The controls changes are primarily associated with the boiler draft controls. Each boiler will require boiler distributed control system (DCS) tuning to deal with the transient impact of the other unit upset. These impacts can be addressed during the design and DCS tuning periods. Below is a discussion on each of the components and how the DCS control logic will be affected by the proposed modifications.

CDS Fan - The existing Unit 2 ID Fan will be renamed to the CDS Fan, as it will serve both Unit 1 and Unit 2. The CDS fan blade pitch control will be modified to control the duct pressure at the common tie-point between the two units. The duct work pressure control set point will be selected to control furnace pressure and subsequent draft losses.

Unit 2 Furnace pressure control will be provided by a new furnace pressure control damper to be installed downstream of the Unit 2 air heater. As the furnace pressure increases, the regulating damper will open to increase gas flow and thus lower the pressure in the furnace.

A new Unit 1 regulating damper will also be installed in the new ductwork, downstream of the Unit 1 ID fan and prior to the tie-in to the scrubber. This damper will control outlet pressure from the Unit 1 ID fan to maintain the Unit 1 ID fan outlet pressure design condition.

The Unit 1 ID fan will continue to control the Unit 1 furnace pressure with the same control strategies as currently implemented. System tuning will be required after implementation to tune the system response, for the new conditions.

There will be minimal changes to the CDS Recirculation Damper logic, however a change to the damper flow set point may be required.

The Project controls modifications are necessary to satisfy the National Fire Protection Association (NFPA) 85 "Boiler and Combustion Systems Hazards Code" minimum requirements that must be met by coal fired power plants with multiple burner boilers and exhaust gas ductwork. NFPA 85 has requirements to prevent boiler explosion and implosion for misoperation of the boiler draft fans. One primary requirement is that for an "Open-flow Air Path". Section 6.5.3.2.1 states the following.

> ***6.5.3.2.1*** *An open-flow air path from the inlet of the FD fans through the stack shall be ensured under all operating conditions.*

Accordingly under operating conditions each boiler enclosure and associated ductwork will be interlocked to provide an "Open-flow Air Path" to purge combustibles from the boiler enclosure. Prior to startup and after a Master Fuel Trip (MFT) the boiler enclosure will be purged. Prior to and after the purge, the Unit isolation damper can be closed to allow maintenance in the offline unit while the other unit can continue to operate.

In addition, NFPA 85 section 6.5.3.2.4 requires an open path when starting the first ID fan and the first FD fan.

> ***6.5.3.2.4*** *Provision of the open path shall be ensured while starting the first ID fan and the first FD fan.*
> ***6.5.3.2.4.2*** *On installations with a single ID fan or FD fan, the following shall apply:*
> *(1) The ID fan's associated control devices and shutoff dampers shall be permitted to be closed as required during the fan's start-up.*
> *(2) The FD fan's associated flow control devices and shutoff dampers shall be brought to the position that limits the starting current for the fan's start-up and then shall be brought to the position for purge airflow during fan operation.*

To startup Unit 1, the CDS fan will be started with fan inlet/outlet dampers closed. Then, after the CDS fan is started and the Unit 1 isolation damper opened, the Unit 1 ID fan will be allowed to start. Once the Unit 1 ID fan is started, the permissives will be met to start the Unit 1 FD fan. DCS control logic will be interlocked for the proper operating sequence.

NFPA 85 section 6.5.1.3.2.2 requires the ductwork to be designed for capability of the ID fan test block.

6.5.1.3.2.2* Negative Transient Design Pressure.
(A) *If the test block capability of the ID fan at ambient temperature is equal to or more negative than -8.7 kPa (-35 in. of water), the negative transient design pressure shall be at least as negative as, but shall not be required to be more negative than, -8.7 kPa (-35 in. of water).*
(B) *If the test block capability of the ID fan at ambient temperature is less negative than -8.7 kPa (-35 in. of water), for example, -6.72 kPa (-27 in. of water), the negative transient design pressure shall be at least as negative as, but shall not be required to be more negative than, the test block capability of the ID fan.*

A portion of the Unit 1 ductwork must be studied to meet this requirement. The test block capability of the CDS fan will be greater than the existing ID fan head capacity. A boiler implosion study of the design limits for the existing Unit 1 ductwork will be performed as part of the Project design, however, the costs associated with any modifications to the existing Unit 1 ductwork to meet test block requirements have not been included in the Project cost estimates. The anticipated costs resulting from the boiler implosion study are expected to be minimal and managed through control system modifications rather than physical modifications to existing ductwork.

As part of meeting the NFPA 85 requirements for the Project, unit trips must be considered. When both units are operating and one unit trips, control feed forward logic will be required to prevent a negative excursion. The control logic will also need to prevent furnace pressure transients on the unit that remains in operation. The control logic will be designed to purge the boiler and allow the operator to restart or shutdown the unit in a controlled manner.

As part of the Project, any condition that trips the CDS fan will require a subsequent master fuel trip of both units and trip of all Unit 1 and 2 fans. Following the fan trip the fan dampers would open to allow natural draft through the boilers.

Several control system changes will be required for combining the Unit 1 exhaust gas into the Unit 2 CDS. In order to comply with NFPA 85, logic changes will also be required to interlock the components to prevent misoperation of the draft systems. The DCS tuning for boiler load ramps and response time of each unit will be required, on both units to test the system response for all conditions.

Although several control system changes are required to allow the units to utilize the common CDS, the resulting controls are not substantially different than other multiple unit configurations that are operating successfully in the industry. The controls changes described in this report are not expected to noticeably change the operability of the plant or increase the risk of equipment failure.

As part of the Project, the shift supervisor and control room operators for each shift will be thoroughly trained in all aspects of the revised plant controls. This training cost is included in the project estimate.

Plant controls will be designed for secure and safe operation of all equipment. Maintenance support will be supplied by on-site staff for routine maintenance activities. Maintenance support for major shutdown work is expected to be contracted.

3.1.2 CEMS Modifications

As part of this proposed Project, the continuous emissions monitoring system (CEMS) plan will be modified such that the existing Unit 2 scrubber inlet SO_2 CEMS location will also measure the SCR outlet NO_x and CO_2.

The common CEMS equipment downstream of the existing Unit 2 ID fan will remain the same as the equipment currently installed on Unit 2. This consists of an X-pattern flow transmitter, a PM CEMs, and a probe for sampling NO_x, SO_2, and CO_2.

The proposed CEMS probe locations are shown on drawing CEMS001 included in Appendix A.

3.1.3 Site Conditions and General Requirements

The following site conditions and general requirements were used as the basis for preliminary design and summarized below.

3.1.3.1 Design Conditions

The site conditions are summarized as follows:

Plant Elevation:	813 ft msl
Extreme Temperatures:	
Maximum Dry Bulb:	103 °F
Minimum Dry Bulb:	-32 °F
Design Conditions:	
Summer (1% coincident):	94°Fdb/73 °Fwb
Winter (99%):	4 °F
Design Relative Humidity	86%

Precipitation:

Mean Annual: 51 inches (National Climatic Data Center CLIM 81.)

Rainfall Depths: (US Department of Commerce/US Weather Bureau - Technical Paper 40).

Duration	100-year Return Period	25-year Return Period	10 year Return Period
1 hour	2.92 inches	2.38 inches	2.11 inches
6 hour	4.59 inches	3.83 inches	3.33 inches
24 hour	6.29 inches	5.21 inches	4.5 inches

Building Code of Record: All Work will be in accordance with the Kentucky Building Code – 2007 including all appendices, amendments, and reference standard.

Wind Design: Per Kentucky Building Code – 2007 to include the following:

a. 90 MPH Basic Ground Wind Speed at 33 feet above ground (3-second gust)
b. $I_W = 1.15$
c. Exposure C
d. No wind shielding will be taken into account.
e. Designed to include Topographic K_{zt} and Directionality K_d Factors as applicable per Code.
f. Structures and equipment to be permanently located indoors will be designed for no less than a 5 psf 'wind' load.

Snow Design: Per Kentucky Building Code – 2007 to include the following:

a. Ground snow load = 15 PSF
b. $I_S = 1.1$
c. Designed to include Exposure C_e and Thermal C_t Factors as applicable per Code.
d. Designed to include drifting increases when applicable due to adjacent structures.
e. Include rain-on-snow load increase for 'roof' areas sloped less than ½ inch per foot.

Ice Loads: Per Kentucky Building Code – 2007 to include the following:

a. Nominal Ice Thickness $t = 0.75$ in.
b. Concurrent Wind Speed $V_c = 30$ mph

Seismic Design: Per Kentucky Building Code – 2007 to include the following:

a. Seismic Importance Factor $I_E = 1.25$
b. Mapped Spectral Accelerations
   (a) Short Period $S_S = 0.266$g, $S_{S,0} = 0.232$g
   (b) 1-second Period $S_1 = 0.097$g, $S_{1,0} = 0.096$g
c. The soil properties at the Project Site are classified as Site Class D (to be verified by Geotechnical investigation).
d. Structures and Equipment shall be considered as Occupancy Category III.

Plant Site Frost Depth: Per Kentucky Building Code – 2007, a minimum depth of 24 in. or erecting on solid rock.

All Materials for the Project shall comply with the OSHA Regulations and Standards 29CFR1910. If conflicts between Kentucky Building – 2007 and OSHA occur, Kentucky Building Code – 2007 to control. All Work performed on Site shall comply with OSHA Regulations and Standards 29CFR1926 and 29CFR1926 Subpart R.

Minimum Design Live Loads:

a.	Ground floor slabs - indoor:	125 psf
b.	Ground floor slabs – outdoor:	250 psf
c.	Grating access platforms:	125 psf
d.	Stairs:	100 psf
e.	Roof live load:	20 psf

f. Driveways, slabs or pavement subject to trucks or fire equipment: AASHTO HS20-44 Loading

3.1.4 Environmental Design Criteria

The Project is based on the information presented in Section 4.0 of this report.

3.1.5 Air Quality Control Chemicals

No additional air quality control chemicals will be required as part of the Project. Pebble Lime will continue to be delivered to site by truck. The existing pebble lime silo and hydration trains will be utilized as part of the Project. Modifications to the hydrated lime feed system will be included to allow dual hydrator operation.

3.1.6 Fuel

The fuel supply for the Project is based on existing coal delivered to site.

3.1.7 Water

The existing sources of water utilized for the CDS are lake water and wastewater. While additional water utilization is expected as part of the Project, no changes to the source of water are expected as part of the Project.

Potable water is currently supplied from the city. No new potable water is expected as part of the Project.

3.1.8 Wastewater

No changes to the existing wastewater system are included or expected as part of the Project.

3.1.9 Air

The existing compressed air system is of adequate design capacity to supply the needs of the new service and instrument air requirements. Any interface tie-in location will be downstream of the existing system compressed air receivers and dryers.

3.1.10 Stacks

Use of the existing stack is expected as part of the Project. No cost has been included for stack modifications other than the demolition and removal of the stack division wall and sealing of the existing Unit 1 stack breaching.

3.1.11 Noise Criteria

A detailed analysis for ambient noise conditions was not performed, however, no increase to the existing plant noise conditions is expected as part of the Project.

3.1.12 Aesthetics and Landscaping

Landscaping consists of seeding and gravel placement for erosion control of disturbed areas. No other landscaping is included.

3.1.13 Geotechnical Data

Geotechnical data will be as determined from existing subsurface investigations. It is not anticipated that additional subsurface investigation will be required for this project.

3.1.14 Construction Power

Power supply for construction will come from the existing electrical system. No new construction transformers are needed.

3.1.15 Electrical Interconnection

This project has minimal electrical interconnection requirements. Spare electrical starters from Unit 1 and Unit 2 will be utilized.

3.1.16 Site Arrangement

The following criteria were considered in developing the site arrangement:

- To optimize, to the greatest extent possible, the interfaces with the existing infrastructure.
- To locate ductwork to minimize cost impacts of the Project and allow space for adequate access for construction and future maintenance.

3.1.17 Future Considerations

There were no future considerations during this definition phase of the Project.

3.2 Facility Scope and Assumptions

3.2.1 Scope of Work

The scope of work that formed the basis of the plant design, cost estimates, and schedule execution, are summarized in the Sections 3.1 and 3.2 of this report.

3.2.2 Cost Estimate

BMcD prepared cost estimates to include all equipment, materials, construction, commissioning and startup activities to construct the Project in accordance with this document. The estimates include Owner's costs provided by EKPC.

4.0 PERFORMANCE ESTIMATES

4.1 Performance Estimate Basis

The performance estimates for this project are based on detailed evaluations of the impacts associated with combining the flue gas streams from Unit 1 and Unit 2 into the Unit 2 CDS. The evaluations that were performed included the following:

1. Calculations based on the CDS Supplier's proprietary design software
2. Conducting tests with a 1/12th scale physical flow model of the new configuration
3. Conducting high flow tests on the actual installed Unit 2 CDS
4. Review of operations data from other units operating in similar velocity regions

The results of the evaluations that were performed concluded that the Unit 2 CDS is capable of achieving compliance with MATS and BART for both Cooper Unit 1 and Unit 2.

4.2 Emissions Estimates

The emissions estimates for the combined operation of both units after the completion of this project are as provided in Table 4-1. These values meet the Consent Decree entered into by U.S. EPA and EKPC for emissions requirements for Unit 2 in addition to being in compliance with both MATS and BART.

Table 4-1: Emissions and Performance Estimates

Parameter	Units	Performance
SO_2	% Removal lb/MMBtu	95[1] 0.10
H_2SO_4	lb/MMBtu	N/A
Particulate Emissions (Filterable)	lb/MMBtu	0.030
Particulate Emissions (Total)	lb/MMBtu	0.045
Hg	lb/TBtu	1.2

[1] Under the Consent Decree between the U.S. EPA and EKPC Cooper 2 is subject to a 30-day rolling 95% SO_2 removal efficiency or a 30-day rolling limit of 0.10 lb/MMBtu.

4.3 Air Permit Impact

Other than the changes to the emissions from Unit 1 described in Section 4.3, this Project is expected to have limited impact on the current Title V air permit. Truck traffic associated with deliveries of pebble lime and waste ash removal are not expected to increase above the design basis values used for determining the fugitive dust emissions that were the basis of the 2010 revision to the permit. The hydrated lime system will be upgraded to allow for the simultaneous operation of both hydrator trains. Although this change will increase the current particulate matter emissions from emission point 09-07, the change results in a calculated increase of less than two tons per year over the current permitted allowable, and the project will result in an overall PM emissions reduction.

5.0 PROJECT EXECUTION APPROACH

Safety will be of the highest priority during project execution. A full time safety professional has been included in the project during all on-site construction. Safety will be a key consideration that will be used when selecting construction contractors for the project. In addition, lessons learned from the favorable safety performance achieved on the previous Cooper Unit 2 project will be implemented on this project.

The execution plan developed for this project is a multiple prime contracting approach. This approach is based on multiple prime contractors executing installation of equipment and materials for the project. The prime contractors will procure commodities and some of the miscellaneous materials.

The Owner will purchase the major equipment and all engineered balance of plant equipment.

6.0 SCHEDULE

6.1 General

The Project schedule is based on COD occurring in April 2016. A Level 1 milestone schedule is included in Appendix D, which includes activities from permitting through commercial operation. This schedule depicts the key milestone dates, key procurement dates and construction interfaces that must occur to meet the scheduled COD. The schedule reflects a 12 month plan for the construction and commissioning period. The schedule also reflects a multiple prime contracting approach for procurement and construction with the Owner being responsible for procurement of the major equipment.

The schedule is driven by the activities required to achieve air permitting, CPCN approval, EKPC approval, and construction contractor awards. Failure to meet the FNTP date could lead to a delay of the project COD.

6.2 Major Equipment

The overall project schedule is based on the equipment lead times shown. The deliveries of the major equipment are based on BMcD's recent in-house project experience. As firm proposals for major equipment have not been received, delivery durations are subject to change.

6.3 Construction

The overall schedule from FNTP through COD is 22 months, which is a typical duration for a project of this magnitude. Based on current long lead time items, the schedule allows adequate time for the contractors to execute their design and procurement in a time frame necessary to support the construction and commissioning schedule.

6.4 Startup

Commissioning will commence at the completion of the Unit 1 and Unit 2 combined outage. The electrical and mechanical systems are commissioned in a sequence to support firing of the units. System operations tuning will be required to synchronize the control systems for the common unit CDS and to tune the CDS to meet the emissions requirements.

6.5 Critical Path

For a commercial operation date in April 2016, construction must start no later than April 2015. The critical path of the construction is driven by procurement and construction of the major equipment and acquiring necessary project permits. In order to support the construction schedule, obtaining permits and the award of the major equipment must be made according to the schedule in Appendix D.

7.0 COST ESTIMATES

7.1 General

The detailed capital cost estimate for the Project is included in Appendix B. The estimated cost for the Project, inclusive of contingency, fee, and escalation, is $14.95 million for the multiple prime contracting approaches discussed in Section 5.0. Table 7-1 provides a summary breakdown of the Capital Cost Estimate.

Table 7-1: Estimated Capital Cost Summary

Combining Unit 1 and Unit 2 CDS	Multiple Prime Contract Approach ($MM)
Project Costs	
Equipment	$3,646,216
Piling / Foundations / Concrete	$623,357
Civil/Demo	$69,990
Structural Steel	$841,961
Ductwork	$3,975,723
Electrical	$114,048
Instrument & Controls	$367,070
Insulation	$975,000
Total Direct Costs	**$10,613,365**
Construction / Project Indirects	
Construction Management & Indirects	$877,000
Engineering - Home Office, Field, Startup	$1,731,912
Insurance	Incl in Owner's Cost
Performance Bond	Incl in Owner's Cost
Permits	Incl in Owner's Cost
Escalation	Incl in Owner's Cost
Contingency	$1,023,863
Total Indirect Costs	**$3,632,775**
Owner's Costs	**$708,700**
Total Project Cost	**$14,954,840**

7.2 Cost Estimate Basis

The following describes the methodology used in the development of the Project cost estimate.

- Estimates are based on the assumptions and scope of supply described in this report.
- Major Engineered Equipment: BMcD estimated costs for the following major equipment based on budgetary quotes received or costs received from recent project experience:
    - Exhaust gas isolation and control dampers
    - CEMS equipment
    - Structural steel and ductwork
- Construction Estimates: Construction commodities and indirect costs were estimated using recent pricing and factored adjustments to quantities from other similar projects in BMcD's in-house database.
- Labor rates: Labor rates and productivity factors were developed based on recent experience from the Cooper Retrofit Air Pollution Project performed on Unit 2.
- Project Indirect: Estimates are based on BMcD's experience as an Owner's Engineer and EPC contractor.

7.2.1 Capital Cost Estimate Scope

Below are listings of the major scope items included and excluded from the cost estimate.

The following major scope items are included in the estimated costs:

- Ductwork from Unit 1 to the Unit 2 CDS inlet.
- Isolation and regulating dampers.
- CEMS equipment.
- Modifications to the CDS equipment and systems.
- Longer fabric filter cages.
- Demolition of existing stack division wall
- Sealing of the existing Unit 1 stack breaching

The following major items are excluded from the estimated costs included in this report.

- Supply and installation of longer fabric filter bags. (Note: Replacement of bags is considered an O&M cost to the existing Unit 2 PJFF since they will require replacement regardless of whether this Project moves forward or not).

7.2.2 Major Capital Cost Estimate Assumptions

Several major assumptions were used in developing the capital cost estimates. These assumptions include the following:

- Facility COD is assumed to be in April of 2016. To achieve this overall project schedule, a FNTP in June of 2014 is required.
- Labor is assumed to be Union based with a working schedule of 10 hours per day, five days per week.
- Contracting and commercial terms as defined in Paragraph 7.2.3.
- The cost for major equipment is based on the budget level Vendor quotes. No allowances/adjustments have been made to account for negotiation of the final terms and conditions and/or final scope.

7.2.3 Major Commercial Terms

The project capital cost estimates were developed based on typical multiple prime contract terms and conditions. The following list highlights the major items. Minor assumptions are either self-evident in the data or have an insignificant effect on the estimated project capital costs.

- The Project is assumed to be executed on a multiple prime contract basis.
- The Project will be executed with durations as shown on the project schedule included in Appendix D with commercial operation occurring in April of 2016. It is assumed the Project will be executed with a schedule sufficient to minimize overtime. A 50 hour work week 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. No additional overtime is included to accommodate a compressed work schedule.
- The cost for a performance bond is included for all work at the rate of 1.5% of the estimated project contract costs. The bond cost is inclusive of a standard one year warranty.

7.3 Operations & Maintenance Estimates

The following is a summary of the additional fixed and variable operating and maintenance (O&M) cost estimates for the Plant in 2013 dollars. A more detailed summary of these costs is included in Appendix C.

- Annual Fixed Operating Costs: No Increase
- Non-Fuel Variable Operating Costs: $4.5 / MWh

O&M costs are based upon the assumptions included in the following paragraphs.

7.3.1 Plant Operation & Fuel

This Project will have very limited impacts to overall plant operation and fuel delivery.

7.3.2 Staffing

This Project will not impact the current plant staffing requirement.

7.3.3 Fixed O&M Costs

No significant equipment maintenance will be required for the new equipment provided with this Project. However, coordination between unit outages will be required to allow for maintenance of common components such as the scrubber, baghouse and Unit 2 ID Fan.

7.3.4 Variable Operating Costs

The variable operating costs include costs that vary with operation of the Plant including the following:

- Pebble Lime consumption costs
- Scrubber waste disposal

7.3.4.1 Assumed Variable Operating Costs

The following are the costs provided by EKPC used in estimating the non-fuel variable O&M costs and are presented in 2013 dollars.

- Pebble Lime: $130/ton
- Waste disposal $3/ton

7.4 Cost Escalation

As this project has a long duration (in excess of one year) between the submitted cost estimate and the anticipated FNTP, there is the potential that future events may cause the equipment, commodities, and labor prices to escalate beyond that included in the Burns & McDonnell estimate. These "triggering events" include:

- Changes in law including consents and regulatory actions
- Actions of the U.S. Environmental Protection Agency (EPA)
- Devaluation of the U.S. currency
- U.S. and regional unemployment rates
- Increase in interest rates
- U.S. or global force majeure events beyond contractor's reasonable control that have an impact on the price or delivery of equipment and materials
- Significant increase in the U.S. electrical power demand that would have an impact on equipment, material, or labor cost

8.0 APPENDICES

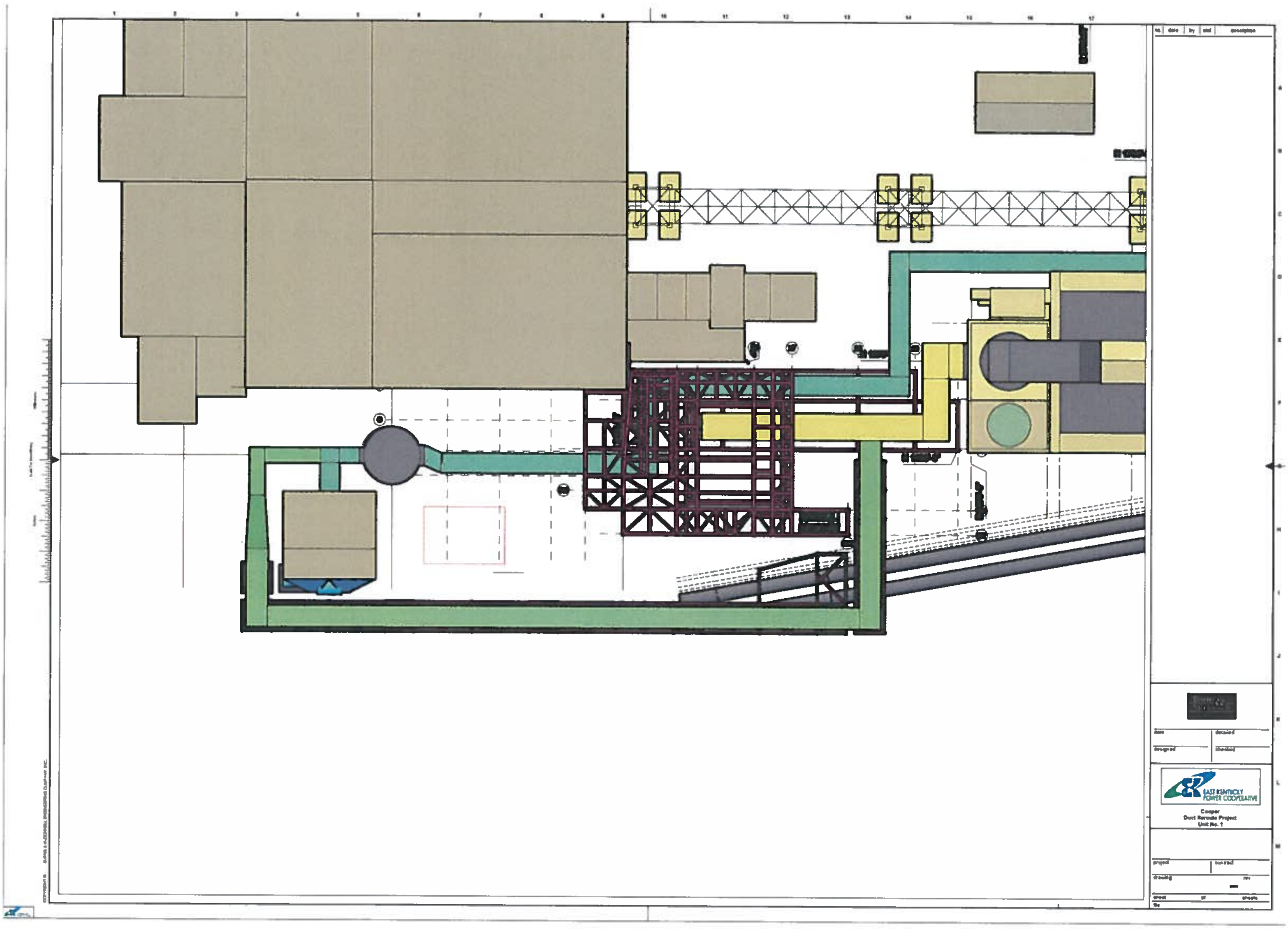
APPENDIX A - SITE PLAN AND GENERAL ARRANGEMENT(S)

APPENDIX B - CAPITAL COST ESTIMATE

APPENDIX C - O&M COST ESTIMATE

APPENDIX D - PROJECT SCHEDULE

APPENDIX A - SITE PLAN AND GENERAL ARRANGEMENT(S)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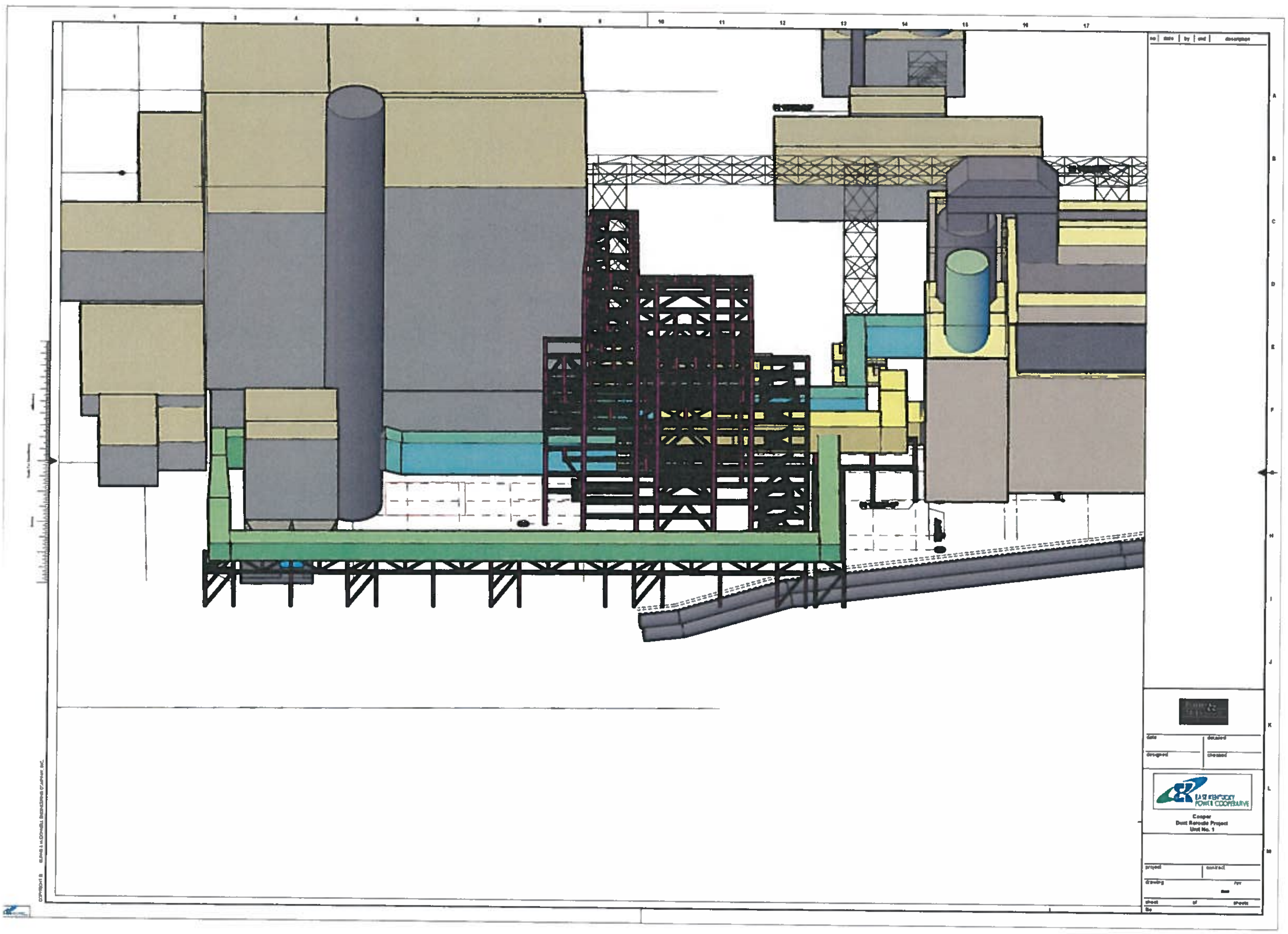
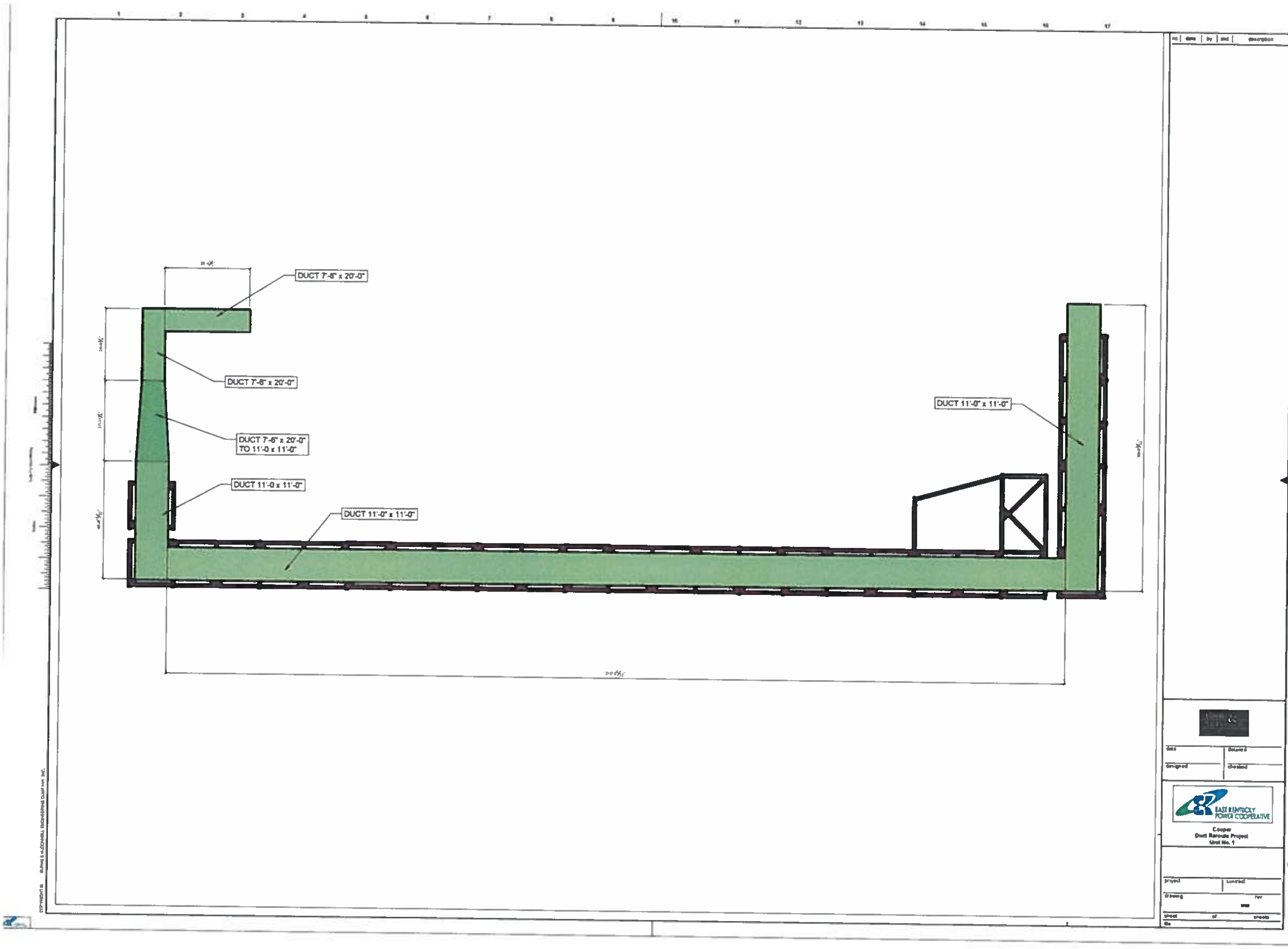
Cooper
Duct Reroute Project
Unit No. 1


EAST KENTUCKY POWER COOPERATIVE
Cooper
Dust Recycle Project
Unit No. 1


DUCT 7'-6" x 20'-0"
DUCT 7'-6" x 20'-0"
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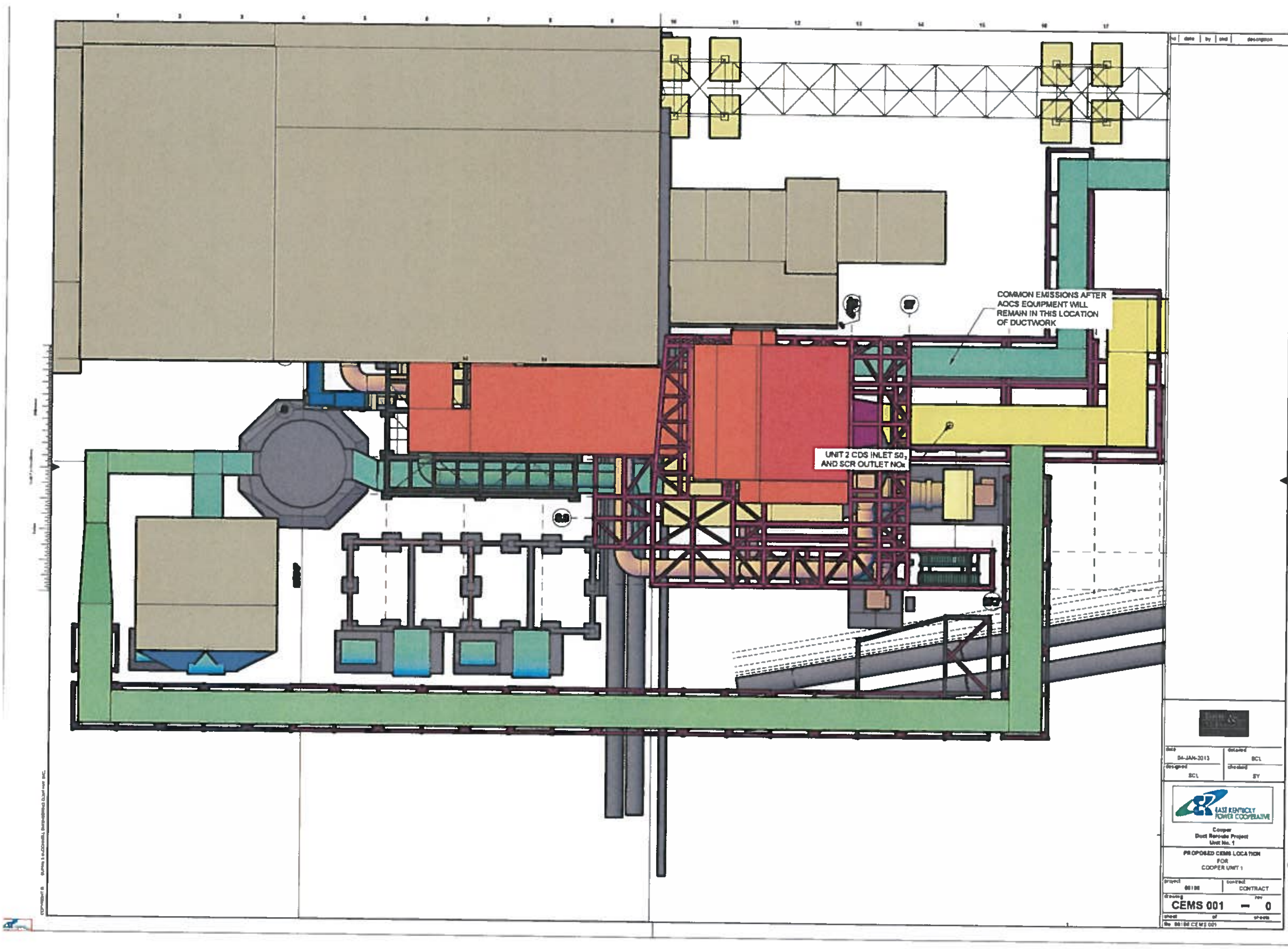
EAST KENTUCKY POWER COOPERATIVE


COMMON EMISSIONS AFTER AOCS EQUIPMENT WILL REMAIN IN THIS LOCATION OF DUCTWORK
UNIT 2 CDS INLET SO_2 AND SCR OUTLET NOx
EAST KENTUCKY POWER COOPERATIVE
Cooper
Duct Reroute Project
Unit No. 1
PROPOSED CEMS LOCATION
FOR
COOPER UNIT 1
04-JAN-2013
SCL
SCL
SY
CONTRACT
CEMS 001
—
0

APPENDIX B - CAPITAL COST ESTIMATE

BUDGETARY COST ESTIMATE
EKPC - COOPER UNIT 1
AQCS UPGRADES
69186
SOMERSET, KY

AREA / DISCIPLINE	Direct Manhours	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Construction Equipment Cost	Total Cost
Equipment	1,668	$118,986	$477,510	$3,035,046	$14,674	$3,646,216
Civil	725	$60,746			$9,244	$69,990
Concrete	4,333	$360,857	$187,523		$74,977	$623,357
Structural Steel	2,783	$285,071		$532,400	$24,490	$841,961
Ductwork	16,855	$2,202,747	$161,430	$1,478,400	$133,146	$3,975,723
Architectural						
Mechanical						
Electrical	831	$86,346	$22,215		$5,487	$114,048
Instruments & Controls				$367,070		$367,070
Insulation				$975,000		$975,000
Total Direct Cost	**27,196**	**$3,114,753**	**$848,678**	**$6,387,916**	**$262,018**	**$10,613,365**

Rev.	Revision Date
0	12/17/12

General Conditions / CM	$877,000
Engineering	$1,731,912
Escalation (included in Owners Costs)	
Warranty	
Total Indirect Cost	**$2,608,912**
Total Direct and Indirect Costs	**$13,222,277**
Contingency	$1,023,863
Fee	
Total	**$14,246,140**
Owner Costs	**$708,700**
Total Project Cost	**$14,954,840**

Burns & McDonnell
SINCE 1898

East Kentucky Power Cooperative
Cooper Station
Unit 1 Scrubber Option
December 14, 2012
Owner Costs

Owner Costs			
Project Development	$0	LS	Allowance for outside engineering costs, etc. to develop the Project that are not included below.
Owner Project Management			
Owners Staff	$225,000	LS	EKPC's management labor and overhead costs for development and execution of the Project. 1 person for 1.5 year at $150,000/yr.
Contract Staff	$102,500	LS	1 - Office Administrative Assistant @ $40k at 1yr and 1 Scheduler @$125k/yr @6 months
Owner Operations Personnel	$25,000	LS	Labor costs for EKPC's operations personnel through start-up. 1 person for 3 months at $100,000/yr.
Owner's Engineer	$0	LS	Outside engineering costs for design, procurement, and construction management through completion of the Project. Included in Project cost estimate.
Owner Legal Council	$0	LS	Allowance for owner's legal costs through completion of the Project.
Owner Startup Engineering	$37,500	LS	Engineering costs for EKPC personnel associated with start-up of the Project. 1 engineer for 3 months at $150,000/yr.
Temporary Utilities			
Power Used During Construction	$45,563	LS	0.75 MW for 10 hours a day, 5 days a week for 6 months.
Waste Removal	$10,000	LS	
Dust Control	$9,000	LS	
Snow Removal	$0	LS	Not Included
Permitting & License Fees			
PSD Permit incl Ambient Air Monitoring	$0	LS	
Environmental Impact Statement	$0	LS	
Wetland Mitigation	$0	LS	
NPDES Permit - Construction & Operating	$0	LS	
Stormwater Control Permit	$0	LS	
CPCN	$0	LS	
Land	$0	LS	Existing.
Water Rights Costs	$0	LS	Existing.
Labor Camps	$0	LS	Does not apply for Project. Adequate housing for construction workers is available in area.
Site Water Supply/Discharge	$0	LS	Existing.
Natural Gas Infrastructure	$0	LS	Not applicable.
Political Concessions / Area Development Fees	$0	LS	Not Included
Start-up Costs		LS	
Fuel - Coal	$0	LS	Not Included
Fuel - Natural Gas Duct Firing	$0	LS	Not applicable.
Variable O&M - Water, chemicals, etc	$0	LS	Not Included
Startup Power	$0	LS	Not Included
Test Power Sales	$0	LS	EKPC does not credit the power sales to the project.
Initial Reagent Inventory - Ammonia	$0	LS	Not applicable.
Site Security	$0	LS	Not Included
Transmission Upgrades	$0	LS	Not Included
Transmission	$0	LS	Not Included
Interconnection	$0	LS	Not Included
Switchyard Modifications	$0	LS	Not Included
Builder's Risk Insurance	$0	LS	Not Included
Performance Bond	$220,537	LS	Estimated Bond Costs
Owners Construction Trailer	$33,600	LS	$2800 per month for 12 months
Spare Parts		LS	
Gas Turbine	$0	LS	Not applicable.
Steam Turbine	$0	LS	Not applicable.
BOP Equipment	$0	LS	Not Included - no new equipment being provided.
Permanent Plant Equipment & Furnishings			
Workshop Tools & Test Equipment	$0	LS	Existing.
Warehouse Space	$0	LS	Existing.
Mobile Equipment, Vehicles	$0	LS	Existing.
Laboratory Equipment & Furniture	$0	LS	Existing.
Kitchen Furniture	$0	LS	Existing.
Locker Room Furniture	$0	LS	Existing.
Building Furniture, dress out etc.	$0	LS	Existing.
Labor Incentives	$0	LS	Not Included
Escalation - Owner Costs	$0	LS	Not Included
Escalation - Project Costs	$0	LS	Not Included
Owner's Contingency	$0	LS	Not Included
Sales Tax	$0	%	Excluded
Financing Fees	$0	LS	Excluded
Interest During Construction	$0	LS	Excluded
Total Owner's Cost	$708,700		

APPENDIX C - O&M COST ESTIMATE

Cooper Unit 1 Estimated O&M Costs

Expense	Year	Cost	
Labor Costs	2013	$52.30	$/hr
Waste Disposal Cost	2013	$3.00	$/ton
Lime Cost	2013	$130.00	$/ton
Lime Purity		95.0%	lb CaO/lb Lime
Inputs			
Capacity Factor	58.0%	%	
wt%S	2.00%	%	
HHV coal	12,000	Btu/lb	
wt%Cl	0.4200%	%	
HR of Plant (net)	10,103	Btu/kWh	
MW_e	116	MW, net	
Fuel Burn Rate	1,172	mmBtu/hr	
FR_{SO2}	3,907	lb/hr	
FR_{HCl}	421.755	lb/hr	
Flowrate at AH Outlet	400,000	acfm	
Calculated Values			
Inlet SO2	3907	lb/hr	
SO2 Removal	95	%	
Stoichiometry	2.25	mol Ca / mol SO2 removed	
Lime Usage	7684	lb/hr	
Lime Usage	19521	tons/yr	
Lime Cost	$ 2,537,672	$/yr	
Waste Generated	11395	lb/hr	
Waste Generated	28949	tons/yr	
Waste Disposal Costs	$ 86,846	$/yr	
Incremental Costs			
Fixed O&M	0	$/yr	
Variable O&M	$ 2,624,518	$/yr	
Variable O&M	**4.45**	$/MWh	
Total O&M Cost	**$ 2,624,518**	$/yr	

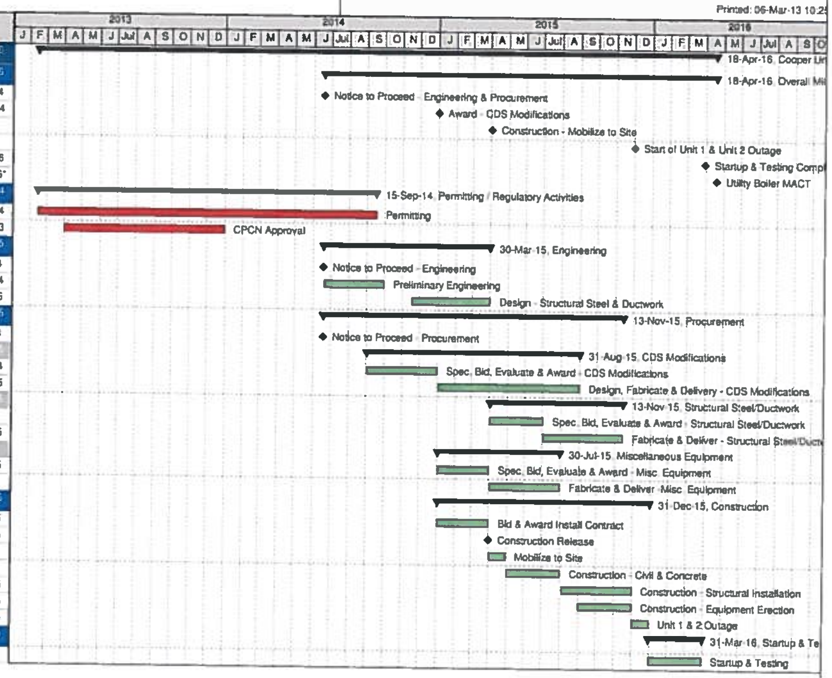
APPENDIX D - PROJECT SCHEDULE

Cooper Unit 1 - Scrubber Option - Level 1

WBS Layout

Status Date: 17-Sep-12
Printed: 06-Mar-13 10:2

Activity ID	Activity Name	Orig Dur	Start	Finish
Cooper Unit 1 - Scrubber Option - Level 1		803	15-Feb-13	18-Apr-16
Overall Milestones		453	19-Jun-14	18-Apr-16
A1070	Notice to Proceed - Engineering & Procurement	0		19-Jun-14
A1080	Award - CDS Modifications	0		31-Dec-14
A1090	Construction - Mobilize to Site	0	01-Apr-15	
A1100	Start of Unit 1 & Unit 2 Outage	0	01-Dec-15	
A1230	Startup & Testing Complete	0		31-Mar-16
A1240	Utility Boiler MACT	0		18-Apr-16*
Permitting / Regulatory Activities		401	15-Feb-13	15-Sep-14
A1000	Permitting	401	15-Feb-13*	15-Sep-14
A1250	CPCN Approval	276	31-Mar-13*	31-Dec-13
Engineering		196	19-Jun-14	30-Mar-15
A1010	Notice to Proceed - Engineering	0		19-Jun-14
A1030	Preliminary Engineering	71	20-Jun-14	30-Sep-14
A1040	Design - Structural Steel & Ductwork	90	18-Nov-14	30-Mar-15
Procurement		357	19-Jun-14	13-Nov-15
A1020	Notice to Proceed - Procurement	0		19-Jun-14
CDS Modifications		253	02-Sep-14	31-Aug-15
A1050	Spec, Bid, Evaluate & Award - CDS Modifications	83	02-Sep-14	31-Dec-14
A1060	Design, Fabricate & Delivery - CDS Modifications	170	02-Jan-15	31-Aug-15
Structural Steel Ductwork		160	01-Apr-15	13-Nov-15
A1110	Spec, Bid, Evaluate & Award - Structural Steel/Ductwork	65	01-Apr-15	01-Jul-15
A1120	Fabricate & Deliver - Structural Steel/Ductwork	95	02-Jul-15	13-Nov-15
Miscellaneous Equipment		148	02-Jan-15	30-Jul-15
A1130	Spec, Bid, Evaluate & Award - Misc. Equipment	63	02-Jan-15	31-Mar-15
A1140	Fabricate & Deliver -Misc. Equipment	85	01-Apr-15	30-Jul-15
Construction		253	02-Jan-15	31-Dec-15
A1150	Bid & Award Install Contract	63	02-Jan-15	31-Mar-15
A1160	Construction Release	0		31-Mar-15
A1170	Mobilize to Site	22	01-Apr-15	30-Apr-15
A1180	Construction - Civil & Concrete	64	01-May-15	31-Jul-15
A1190	Construction - Structural Installation	83	03-Aug-15	30-Nov-15
A1200	Construction - Equipment Erection	62	01-Sep-15	30-Nov-15
A1210	Unit 1 & 2 Outage	31	01-Dec-15	31-Dec-15
Startup & Testing		64	31-Dec-15	31-Mar-16
A1220	Startup & Testing	64	31-Dec-15	31-Mar-16



Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
◆ Milestone
% Complete

Date	Revision	Checked	Approved

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	CASE NO. 2013-00259

EXHIBIT 10

DIRECT TESTIMONY OF ISAAC S. SCOTT

ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 21, 2013

Q. Please state your name, business address, and occupation.

A. My name is Isaac S. Scott and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Manager of Pricing for EKPC.

Q. Please state your education and professional experience.

A. I received a B.S. degree in Accounting, with distinction, from the University of Kentucky in 1979. After graduation I was employed by the Kentucky Auditor of Public Accounts, where I performed audits of numerous state agencies. In December 1985, I transferred to the Kentucky Public Service Commission ("Commission") as a public utilities financial analyst, concentrating on the electric and natural gas industries. In August 2001, I became manager of the Electric and Gas Revenue Requirements Branch in the Division of Financial Analysis at the Commission. In this position I supervised the preparation of revenue requirement determinations for electric and natural gas utilities as well as determined the revenue requirements for the major electric and natural gas utilities in Kentucky. I retired from the Commission effective August 1, 2008. In November 2008, I became the Manager of Pricing at EKPC.

Q. Please provide a brief description of your duties at EKPC.

A. As Manager of Pricing, I am responsible for rate-making activities which include designing and developing wholesale and retail electric rates and developing pricing concepts and methodologies. I report directly to the Director of Regulatory and Compliance Services.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address several items associated with the proposed duct reroute project at the John Sherman Cooper Unit 1 ("Project"). First, I will describe the cost of the Project. Second, I will describe how EKPC plans to finance the capital costs for the Project. Third, I will briefly describe the current environmental compliance plan and the addition of the Project. Fourth, I will discuss EKPC's proposed return that should be earned on the Project. Fifth, I will discuss how the Project would be reflected in the monthly environmental surcharge mechanism and the proposed revisions to the monthly environmental surcharge reporting formats. Finally, I will describe the bill impacts of this addition for wholesale and retail customers

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

- Exhibit ISS-1, a schedule showing the current environmental compliance plan and the addition of the Project.
- Exhibit ISS-2, a sample copy of the monthly environmental surcharge reporting formats which reflect the inclusion of the Project.
- Exhibit ISS-3, a schedule showing the determination of the Base Environmental Surcharge Factor ("BESF") reflecting retirements and replacements of utility plant associated with the Project.
- Exhibit ISS-4, an estimate of revenue increases resulting from the inclusion of the Project and the estimated bill impact on retail customers.

Q. Could you describe the cost of the Project?

A. The estimated total capital cost of the Project is $14,954,480. The estimated total capital cost includes:

- Equipment and material costs of $7,498,612;
- Capitalized labor costs of $3,114,753;
- Indirect engineering and general costs of $2,608,912;
- Contingency costs of $1,023,863; and
- Project administration, temporary utilities, performance bond, and other associated owner's costs of $708,700.

A detailed breakdown of the estimated total capital cost can be found in Appendix B of the "Cooper Unit 1 Duct Reroute Project Definition Report," which is attached to the direct testimony of Mr. Andrews.

Q. Has EKPC purchased any equipment for the Project?

A. No purchases of equipment have been made. Although Burns & McDonnell have 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 2014.

Q. How will EKPC finance the construction of the Project?

A. Initially, EKPC plans to finance the Project with internally generated funds or short-term borrowings. EKPC eventually intends to finance the Project by utilizing Federal Financing Bank loan funds through a Rural Utilities Service guaranteed loan. The interest rate for such a loan will not be known until funds are drawn under the loan.

Q. Would you please provide a brief description of EKPC's current environmental compliance plan?

A. EKPC currently has 13 projects in its environmental compliance plan. Exhibit ISS-1 lists each of the projects, the pollutant or waste/by-product to be controlled, the control facility, the generating station, the applicable environmental regulation addressed by the project, the applicable environmental permit, the completion date of the project, and the project cost. Projects 1 through 4 were approved by the Commission in Case No. 2004-00321.[1] Projects 5 through 10 were approved by the Commission in Case No. 2008-

[1] Case No. 2004-00321, Application of East Kentucky Power Cooperative, Inc. for Approval of an Environmental Compliance Plan and Authority to Implement an Environmental Surcharge, final Order dated March 17, 2005.

00115.[2] Projects 7 through 9 were amended by and Projects 11 through 13 were approved by the Commission in Case No. 2010-00083.[3] The Project will be Project 14.

Q. Could you discuss the return EKPC would propose for the Project?

A. The settlement agreement approved in Case No. 2004-00321 provided that EKPC's rate of return would be based on a weighted average cost of debt issuances directly related to the projects in its environmental compliance plan ("average cost of debt") multiplied by a Times Interest Earned Ratio ("TIER") factor. The average cost of debt could be updated to reflect current average debt cost as of the end of each six-month environmental surcharge review period. EKPC is proposing that this approach be continued.

If the Commission grants the requested Certificate of Public Convenience and Necessity ("CPCN") for the Project and approves EKPC's request to amend its environmental compliance plan to include the Project, EKPC would propose that the return authorized for the other projects in the amended environmental compliance plan be applied to the Project. EKPC is not seeking a separate or distinct return on the Project.

Q. Using the approach you have just described and based on today's conditions, if the CPCN had been granted and the project had been approved for inclusion in the EKPC environmental compliance plan, what return would EKPC be proposing for the Project?

A. EKPC would propose that the TIER component of the return on the Project be based on a 1.50 TIER. The Commission approved a 1.50 TIER for environmental surcharge purposes in Case No. 2011-00032.[4]

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[2] Case No. 2008-00115, Application of East Kentucky Power Cooperative, Inc. for Approval of an Amendment to Its Environmental Compliance Plan and Environmental Surcharge, final Order dated September 29, 2008.

[3] Case No. 2010-00083, Application of East Kentucky Power Cooperative, Inc. for Approval of an Amendment to Its Environmental Compliance Plan and Environmental Surcharge, final Order dated September 24, 2010.

EKPC currently has pending before the Commission in Case No. 2013-00140[5] a proposal that the average cost of debt component should reflect the applicable debt interest rates as of December 31, 2012. As of December 31, 2012, the applicable average cost of debt was 4.057%.

Using a TIER of 1.50 and an average cost of debt of 4.057% would result in a rate of return of 6.086%.

Q. Could you discuss how the Project would be reflected in the surcharge mechanism?

A. During the construction phase of the Project, EKPC is proposing that it be permitted to earn a return on the monthly Construction Work In Progress ("CWIP") balance. This request is consistent with treatment approved in Case No. 2008-00115. Upon completion, EKPC is proposing that it be permitted to begin recovery of depreciation, return, insurance expense, taxes, and operation and maintenance expenses associated with the Project. I would like to note that the addition of the Project will not require any revisions to the environmental surcharge tariff sheets.

Q. Will any revisions to the monthly environmental surcharge reporting formats be necessary?

A. Yes. The proposed revisions to the monthly reporting formats are shown in Exhibit ISS-2. EKPC believes that two revisions will be needed to the monthly environmental surcharge reporting formats. First, Form 2.1 – Plant, CWIP, Depreciation, Taxes and Insurance Expenses will need to be revised to include Project 14 – Cooper 1 - Ductwork.

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[4] Case No. 2011-00032, An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of East Kentucky Power Cooperative, Inc. for the Six-Month Billing Period Ending December 31, 2010; and the Pass-Through Mechanism for Its Sixteen Member Distribution Cooperatives, final Order dated August 2, 2011.

[5] Case No. 2013-00140, An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of East Kentucky Power Cooperative, Inc. for the Six-Month Billing Period Ending December 31, 2012 and the Pass Through Mechanism for Its Sixteen Member Distribution Cooperatives; see page 9 of the Direct Testimony of Isaac S. Scott, filed June 14, 2013.

Second, Form 2.5 – Operating and Maintenance Expenses will need to be revised to include a maintenance expense account related to the Project. The Project calls for the installation of new isolation dampers on both Cooper Unit 1 and Unit 2. EKPC anticipates there will be maintenance expenses associated with these isolation dampers. EKPC proposes to include this maintenance expense in two line items on Form 2.5. The maintenance expense associated with the Cooper Unit 1 isolation dampers would be included in a new line item in the "Maintenance" section of the format, under Account No. 512000 titled "Maintenance of Cooper Unit #1 Ductwork." The maintenance expense associated with the Cooper Unit 2 isolation dampers would be included in the existing line item in the "Maintenance" section of the format, also under Account No. 512000 titled "Maintenance of Cooper Unit #2 AQCS."

EKPC has indicated that it expects to incur additional lime and waste disposal operation and maintenance expenses in conjunction with the Project. EKPC proposes to reflect these additional expenses in existing line items on Form 2.5 for Account Nos. 512000 and 506001 established for the Cooper Unit 2 Air Quality Control System ("AQCS"). Thus no revisions will be required to recognize the additional lime and waste disposal expense.

Q. Will the Project result in any retirements or replacements of existing utility plant at Cooper Unit 1 or Cooper Unit 2?

A. EKPC has identified several retirements or replacements of existing utility plant resulting from the Project. At Cooper Unit 1, the existing ductwork that connects Unit 1 to the stack will be removed. Existing pressure transmitters and temperature probes will be replaced. The continuous emission monitors ("CEMs") for sulfur dioxide, carbon dioxide, nitrogen oxide, and flow will be retired.[6] At Cooper Unit 2, the cages for the fabric filter bags, a component of the AQCS, will be replaced as EKPC will be utilizing larger filter bags in the future. The hydrated lime silo vent fan and motor will also be replaced.

Q. Will any of the Cooper Unit 1 retirements or replacements result in an amount to recognize in the BESF component of the surcharge mechanism?

A. The Cooper Unit 1 utility plant retirements or replacements would currently be recovered through existing EKPC base rates, so the possibility exists that a BESF component would be necessary. However, it should be noted these retirements or replacements are not major components of the generating station, like a boiler or precipitator. Consequently, identifying the original cost and corresponding accumulated depreciation for the plant to be retired or replaced may be difficult.

EKPC has reviewed its accounting records and determined an original cost of $635,014 for the utility plant to be retired or replaced. The accounting records also indicate that these items of utility plant are fully depreciated. With the utility plant fully depreciated, there would be no corresponding depreciation expense or property taxes. EKPC was not able to identify any operating and maintenance expense associated with these portions of utility plant. The only expense that could be identified was property insurance.

Exhibit ISS-3 is a calculation of the possible BESF component based on the accounting information. EKPC believes that the resulting BESF of 0.000033% is de minimus and proposes that no BESF be recognized in the environmental surcharge mechanism as a result of the Project.

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[6] However, the CEMs for mercury, which are included in Project 10 of EKPC's approved environmental compliance plan, will only be relocated and will continue in service.

Q. Will any of the Cooper Unit 2 retirements or replacements result in an amount to recognize in the BESF component of the surcharge mechanism?

A. No. The replacements at Cooper Unit 2, the cages and hydrated lime silo vent fan and motor, are currently recovered through the environmental surcharge as part of Project 11 of EKPC's approved environmental compliance plan. These items are not in existing base rates and will not result in a BESF component for the surcharge mechanism. EKPC will remove the original cost, accumulated depreciation, depreciation expense, property taxes, and property insurance associated with the replaced utility plant from the balances reported on Form 2.1 for Project 11 in the month the replacements go into service. Operating and maintenance expenses associated with the replaced utility plant will also cease in the month the replacement go into service.

The capital costs associated with Project 14 will be recognized as CWIP during construction on Form 2.1. The corresponding property taxes and property insurance for Project 14 will also be recognized on Form 2.1 during construction. Once the replacements included in Project 14 go into service, the original cost, accumulated depreciation, depreciation expense, property taxes, and property insurance will be included on Form 2.1 and allowed operating and maintenance expenses will be included on Form 2.5.

EKPC proposes to include supplemental information concerning when the replacements go into service as part of the monthly environmental surcharge filing in the applicable month.

Q. Could you describe the bill impacts on the wholesale and retail customers associated with the inclusion of the Project in the surcharge?

A. Once the Project becomes operational, EKPC estimates that the annual revenue requirement impact would be $3,598,658. The calculation of this estimate is shown on Exhibit ISS-4. This estimated annual revenue requirement translates into an increase of approximately 0.43% in the environmental surcharge for all customer classes at wholesale and would be passed through as an approximate 0.31% retail increase. The estimated increase on an average residential customer's monthly bill would be approximately $0.27.

I would like to note that the bill impacts discussed above are different from those included in the July 5, 2013 memorandum to the Member Systems concerning this application. While finalizing the application, EKPC discovered that a system-wide, overall average variable operating and maintenance cost factor had been used in the calculation of the fixed charge rate. To determine the bill impact for the Project, it is more appropriate to utilize a variable operating and maintenance cost factor related to the project. When this was done, the bill impacts I discuss above were the result.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBITS

Document	Exhibit
Schedule of Existing and Proposed Environmental Compliance Plan Projects	1
Schedule of Monthly Environmental Surcharge Reporting Formats	2
Base Environmental Surcharge Factor Calculation	3
EKPC Annual Revenue Requirement Calculation	4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	**CASE NO. 2013-00259**

AFFIDAVIT

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Isaac S. Scott, 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.

Isaac S. Scott

Subscribed and sworn before me on this 21st day of August, 2013.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

EAST KENTUCKY POWER COOPERATIVE, INC
ENVIRONMENTAL COMPLIANCE PLAN
PURSUANT TO ENVIRONMENTAL SURCHARGE LAW

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Project	Pollutant or Waste/By-Product To be Controlled	Control Facility	Generating Station	Environmental Regulation	Environmental Permit	Actual or Scheduled Completion	Actual (A) or Estimated (E) Project Cost
1.	Fly Ash/Particulate NOx & SO2	Boiler SNCR Baghouse Flash Dry Absorber	Gilbert	401 KAR Ch. 45 CAAA Sec.404 40 CFR Part 72 401 KAR 50:035 CAAA Sec.407 40 CFR Part 76	081-0005 V-97-050 Rev. 1	2005	$69.6 M (A)
2.	Particulate	Precipitator	Spurlock 1	401 KAR 61:015	V-95-050 (Revision 1)	2003	$24.3 (A)
3.	NOx	SCR	Spurlock 1	CAAA Sec. 407 40 CFR Part 76	V-97-050	2003	$84.4 M (A)
4.	NOx	SCR	Spurlock 2	CAAA Sec. 407 40 CFR Part 76	V-97-050	2002 Fall 2007 & Spring 2008	$47.2 (A)
5.	NOx	Low NOx Burner	Dale	CAN:06-cv-00211 40 CFR Part 76.7 Title IV-A, 42 USC 7651-7651o, Sect 502, 401KAR51:160	V-04-038	Fall 2007	$2.0 M (A)
6.	NOx	NOx Reduction Equipment	Spurlock 1	40 CFR Part 76.7 CAN 04-34-KSF	V-06-007	Spring 2009	$3.09 M (A)
7.	SO2	Scrubber	Spurlock 2	CAN 04-34-KSF CAAA Sec 405	V-97-050 Rev. 1	Oct. 2008	$194.1 M (A)
		Switchyard Improvements				In Svce	$8.396 M (A)
		Isolation Valve	Spurlock 2 Scrubber	40CFR Part 76.7 CAN 04-34-KSF CAAA Sec 405 CAAA Sec 404	V-06-007, Rev 2	Fall 2010	$787,793 (A)
8.	SO2	Scrubber	Spurlock 1	CAN 04-34-KSF CAAA Sec 404	V-97-050 Rev. 1	Spring 2009	$145.8 M (A)
		Switchyard Improvements				In Svce	$1.26 M (A)
		Isolation Valve	Spurlock 1 Scrubber	40CFR Part 76.7 CAN 04-34-KSF CAAA Sec 405 CAAA Sec 404	V-06-007, Rev 2	Spring 2011	$677,992 (A)
9.	Fly Ash/Particulate NOx & SO2	Boiler SNCR Baghouse Flash Dry Absorber	Spurlock 4	401 KAR Ch. 45 CAAA Sec.404 40 CFR Part 72 401 KAR 50:035 CAAA Sec.407 40 CFR Part 76	V-06-007	April 2009	$84.8 M (A)
		Ash Silos	Spurlock 4	401 KAR 63:010	V-06-007	Summer 2010	$11.7 M (A)

EAST KENTUCKY POWER COOPERATIVE, INC
ENVIRONMENTAL COMPLIANCE PLAN
PURSUANT TO ENVIRONMENTAL SURCHARGE LAW

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Project	Pollutant or Waste/By-Product To be Controlled	Control Facility	Generating Station	Environmental Regulation	Environmental Permit	Actual or Scheduled Completion	Actual (A) or Estimated (E) Project Cost
10.	PM & Mercury CEMS	Stack Emissions Monitoring	Spurlock Dale Cooper	40 CFR Part 60 App. B, PS 11, & App. F Proced. 2. CD para 97-102. 40 CFR 75	CAN 04-34-KSF	Spring 2010	$2.9 M (A)
11	NOx and SO2, Particulate Matter	Air Quality Control System	Cooper 2	Consent Decree CAN 04-34-KSF KY BART SIP	V-05-082 R1	Summer 2012	$222 M (A)
12	Coal Combustion by-products (CCB)	Landfill Area C Expansion and Sediment Pond Construction	Spurlock 1, 2, 4, Gilbert; Spur 1, 2 Scrubbers	Clean Water Act (CWA) Section 404	KPDES No. KY0022250	Fall 2010	$6.5 M (E)
13	SOx, H2SO4, Mercury	Replacement of Retired Ductwork	Spurlock Unit #2	CFR Title 40, Part 51 CFR Title 40, Part 52 (New Source Review)	V-06-007	Spring 2010	$2.8 M (A)
14	NOx and SO2, Particulate Matter	Ductwork to Connect to Existing Air Quality Control System	Cooper 1	Mercury Air Toxics Rule, 40 CFR Parts 60 & 63 EPA BART & KY BART SIP, 40 CFR Parts 51 & 52	V-05-082R1	Summer 2016	$15 M (E)

Form 2.1

East Kentucky Power Cooperative, Inc.
Environmental Surcharge Report
Plant, CWIP, Depreciation, & Taxes and Insurance Expenses

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Project No.	Description	Eligible Gross Plant in Service	Eligible Accumulated Depreciation	CWIP Amount Net of AFUDC	Eligible Net Plant in Service (2)-(3)=(5)	Monthly Depreciation Expense	Monthly Tax Expense	Monthly Insurance Expense
1	Gilbert							
2	Spurlock 1 - Precipitator							
3	Spurlock 1 - SCR							
4	Spurlock 2 - SCR							
5	Dale 1 & 2 - Low NOx Burners							
6	Spurlock 1 - Low NOx Burners							
7	Spurlock 2 - Scrubber							
8	Spurlock 1 - Scrubber							
9	Spurlock 4							
10	Spurlock, Cooper & Dale - Continuous Monitoring Equipment							
11	Cooper 2 - Air Quality Control System							
12	Spurlock - Landfill Area C Expansion							
13	Spurlock 2 - Replace Ductwork							
14	**Cooper 1 - Ductwork**							
	Total							

Form 2.5

East Kentucky Power Cooperative, Inc.
Environmental Surcharge
Operating and Maintenance Expenses
For the Expense Month Ending ________

	Expense Type	Acct No.		Account Description	Amount
I	Ash Handling	501010	CPXX	Fuel Coal Cooper (Unit # 2 AQCS)	xx
		501010	SP03	Fuel Coal Gilbert	xx
		501010	SP04	Fuel Coal Spurlock 4	xx
II	Operating Expense - Ammonia & Limestone	506001	CO00	Misc Steam Power Expense - Cooper	xx
		506001	COXX	Misc Steam Power Expense - Cooper Unit # 2 AQCS	xx
		506001	DA00	Misc Steam Power Expense - Dale	xx
		506001	SP01	Misc Steam Power Expense - Spurlock 1	xx
		506001	SP02	Misc Steam Power Expense - Spurlock 2	xx
		506001	SP03	Misc Steam Power Expense - Gilbert	xx
		506001	SP04	Misc Steam Power Expense - Spurlock 4	xx
		506001	SP21	Misc Steam Power Expense - Spurlock 1	xx
		506001	SP22	Misc Steam Power Expense - Spurlock 2	xx
III	Air Permit Fees	506002	CP00	Misc Steam Power Environmental Cooper	xx
		506002	DA00	Misc Steam Power Environmental Dale	xx
		506002	SP00	Misc Steam Power Environmental Spurlock	xx
IV	Maintenance	**512000**	**CPXX**	**Maintenance of Cooper Unit # 1 Ductwork**	**xx**
		512000	CPXX	Maintenance of Cooper Unit # 2 AQCS	xx
		512000	SP01	Maintenance of Boiler Plant Spurlock 1	xx
		512000	SP02	Maintenance of Boiler Plant Spurlock 2	xx
		512000	SP03	Maintenance of Boiler Plant Gilbert	xx
		512000	SP04	Maintenance of Boiler Plant Spurlock 4	xx
		512000	SP21	Maintenance of Boiler Plant Scrubber 1	xx
		512000	SP22	Maintenance of Boiler Plant Scrubber 2	xx
				Total	$ XX

Determination of BESF
Retirements and Replacements Associated with the
Cooper Unit 1 Project

Expenses		
1. Depreciation Expense	$0	Assets fully depreciated.
2. Operation & Maintenance	$0	No O&M specifically associated with the plant components to be retired or replaced.
3. Property Tax and Insurance	$259	No property tax on fully depreciated assets; property insurance determined by applying applicable premium to original book cost of assets.
4. Total Expenses	$259	
Return on Rate Base		
5. Rate Base		
Original Book Cost	$635,014	
Less Accumulated Depreciation	$635,014	
Subtotal	$0	
Plus Cash Working Capital	$0	1/8 of O&M, line 2
Total Rate Base	$0	
7. Apply rate of return to Rate Base	6.786%	Authorized in Case No. 2011-00032.
8. Return on Rate Base	$0	
9. Total Revenue Requirement:		
Total Expenses	$259	
Return on Rate Base	$0	
Total Revenue Requirement	$259	

Determination of Member System Allocation Percentage

Revenues from December 2011 Environmental Surcharge filing; last month of forecasted test year of last rate case.

10. Member System Revenus	$754,300,857	96.50%
Off System Sales Revenues	$27,324,301	3.50%
Total Revenues	$781,625,158	100.00%

11. Total Revenue Requirement	$259
Member System Allocation Percentage	96.50%
Jurisdictional Revenue Requirement	$250

Calculation of BESF Related to Cooper Unit 1 Project

12. Jurisdictional Revenue Requirement	$250	
13. Member System Revenues	$754,300,857	December 2011 Filing, Form 3.0; excludes Environmental Surcharge Revenues
BESF [Line 12 divided by Line 13]	0.000033%	

Based on the above calculation, EKPC believes the calculated BESF is de minimus and proposes that no BESF should be recognized in EKPC's environmental surcharge mechanism as a result of the Cooper Unit 1 Project.

Exhibit ISS-4

EAST KENTUCKY POWER COOPERATIVE
ESTIMATED COST RECOVERY IMPACT OF
COOPER UNIT 1 PROJECT

Estimated Annual Revenue Requirements

Capital Costs	$14,954,840	from Project Definition Report
Fixed Charge Rate	24.064%	
Estimated Annual Revenue Requirements	$3,598,658	

Derivation of Fixed Charge Rate

	Average Factor	
Interest	4.057%	Proposed in Case No. 2013-00140
TIER (Based on 1.50)	2.029%	
Depreciation	0.370%	
Property Taxes	0.015%	
Property Insurance	0.043%	
Subtotal	6.514%	
Fixed O&M	0.000%	
Variable O&M	17.550%	
Total Fixed Charge Rate	24.064%	

Variable O&M average factor determined by dividing estimated variable O&M costs of $2,624,518 by the estimated capital costs of $14,954,840; both amounts from the Project Definition Report.