BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR AN APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	CASE NO. 2011-00401

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION TO KENTUCKY POWER COMPANY

Kentucky Power Company ("Kentucky Power"), pursuant to 807 KAR 5:001, is to file with the Commission the original and 15 copies of the following information, with a copy to all parties of record. The information requested herein is due on or before January 27, 2012. Responses to requests for information shall be appropriately bound, tabbed and indexed. Each response shall include the name of the witness responsible for responding to the questions related to the information provided.

Each response shall be answered under oath or, for representatives of a public or private corporation or a partnership or association or a governmental agency, be accompanied by a signed certification of the preparer or the person supervising the preparation of the response on behalf of the entity that the response is true and accurate to the best of that person's knowledge, information, and belief formed after a reasonable inquiry.

Kentucky Power shall make timely amendment to any prior response if it obtains information which indicates that the response was incorrect when made or, though correct when made, is now incorrect in any material respect. For any request to which Kentucky Power fails or refuses to furnish all or part of the requested information, Kentucky Power shall provide a written explanation of the specific grounds for its failure to completely and precisely respond.

Careful attention shall be given to copied material to ensure that it is legible. When the requested information has been previously provided in this proceeding in the requested format, reference may be made to the specific location of that information in responding to this request.

1. Refer to page 3, paragraph 6, of Kentucky Power's Application ("Application"), which discusses its December 2010 notice of termination of the American Electric Power Company ("AEP") Interconnection Agreement ("Pool Agreement").

a. Provide a copy of Kentucky Power's December 2010 notice.

b. Explain whether there are any other agreements to which Kentucky Power is a party that are affected by the termination of the Pool Agreement.

c. If the answer to part b. of this Item is yes, identify the agreements, their terms, and the potential impact to Kentucky Power ratepayers.

d. Explain whether termination notices were given for those agreements. If notice was given, provide a copy of each such notice.

2. Refer to page 3, paragraph 6, of the Application. It states, "[i]t is unknown at this time whether the AEP Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party

contracts with each other for power sales and purchases or asset transfers, or if each company will operate independently."

a. Explain when a decision concerning the future of the AEP Pool Agreement is expected.

b. Describe any potential financial impact the termination of the AEP Pool Agreement will have on Kentucky Power's ratepayers.

3. Refer to pages 4 and 5, paragraph 9, of the Application, which discusses the Consent Decree in *United States v. American Electric Power Service Corp.*, Civil Action C2-99-1250 ("Consent Decree") entered by the United States District Court for the Southern District of New York. Provide the following:

a. Provide the date on which the civil action was filed;

b. Provide a copy of the Consent Decree;

c. If not specifically identified in the Consent Decree, provide a list of the AEP generating facilities which were subject to the Consent Decree; and

d. If any AEP generating facilities are subject to the Consent Decree but were not the subject of the civil action, explain why those facilities are subject to the Consent Decree.

4. Refer to page 7, paragraph 15, of the Application. It states, "Kentucky Power currently anticipates retiring Big Sandy Unit 1 by January 1, 2015, and will make all requisite filings related to this retirement by separate application." Explain Kentucky Power's reasons for retiring Big Sandy Unit No. 1 by January 1, 2015.

5. Refer to page 7, lines 7–8, of the Direct Testimony of John M. McManus ("McManus Testimony").

a. Provide the annual NO_x and SO_2 allowance caps for Kentucky as established by the Cross-State Air Pollution Rule ("CSAPR").

b. Provide the ozone season NO_x allowance cap for Kentucky.

c. For 2010, provide the tons of NO_x and SO_2 emitted by Big Sandy Units 1 and 2.

6. Refer to the McManus testimony at page 7, lines 10 and 11.

a. Explain whether Kentucky exceeds its annual allocation of NO_x and SO_2 allowances by 18 percent.

b. During 2010, did Big Sandy Unit 1 or 2 exceed the CSAPR annual allowance caps by 18 percent? If so, by how much did they exceed the CSAPR caps?

7. Refer to page 12 of the McManus Testimony, lines 14-20. It states, "(i)n addition, as supported by Company witness Weaver, the extraordinary brief compliance window will require KPCo to operate Big Sandy Unit 2 in an uncontrolled fashion, but under a potentially constrained dispatch. This is due to the fact that the timeframe to permit and install an FGD system is beyond the proposed compliance window as discussed by Company witness Walton. In essence, the timing contained in the rule already puts us behind schedule."

a. Explain how the compliance timeline contained in CSAPR already puts Kentucky Power behind schedule.

b. Explain when Kentucky Power first became aware that installation of a wet or dry Flue Gas Desulfurization system ("FGD" or "scrubber") on Unit 2 would be required on the unit in order to comply with the Environmental Protection Agency ("EPA") requirements.

8. Refer to page 14 of the McManus Testimony, lines 12-17. It states, "the Consent Decree requires installation of a FGD system on Unit 2 by the end of 2015. This aligns with the compliance schedule for the MACT ["Maximum Achievable Control Technology"] rule assuming an additional year for a major retrofit. While the CSAPR program will result in having to reduce SO_2 emissions from the unit prior to that time, it can be achieved with curtailment of operation and supplementing the allowance allocation with allowances from other sources."

a. Explain what is meant by curtailment of operation, including but not limited to the number of hours per year of operation and the percentage of available generation.

b. Explain further supplementing the allowance allocation with allowances from other sources including the source of allowances, the number of allowances, and the associated costs of those allowances.

9. Refer to page 17 of the McManus Testimony, lines 10-12, which indicates that it is estimated that the "issuance of the modified air permit" will take up to 18 months from the time the application is submitted.

a. What is the basis for the 18-month estimate?

b. Discuss the impact on construction and compliance if the issuance of the modified air permit takes longer than 18 months.

10. Refer to page 24 of the McManus Testimony, lines 2-4. It states, "the 2007 NSR ["New Source Review"] Consent Decree requires the Company to move quickly on the retrofit of equipment for Big Sandy Unit 2 in order to ensure that it remains a source of reliable, low-cost electricity for KPCo's customers."

a. Based on currently available information, provide the average cost per kWh of electricity produced by Unit 2 and the "as of" date.

b. Provide the projected average cost per kWh of electricity produced by Unit 2 once the retrofits are completed in 2016.

11. Explain how Kentucky Power plans to meet the Hazardous Air Pollutants Rule as it relates to mercury, HCL, SO_3, and other pollutants.

12. Provide the expected service life of Big Sandy Unit 2 after the FGD upgrade.

13. Regarding the environmental projects associated with the AEP Pool surplus companies as outlined in Exhibit JMM-1, provide the capital cost estimates for each of those projects.

14. Refer to page 8 of the Direct Testimony of Lila P. Munsey ("Munsey Testimony"), lines 6-8. It states, "[t]he environmental projects being installed on Ohio Power Plants (OPCo) and Indiana and Michigan Company (I&M) plants could increase the environmental charges to KPCo."

a. Describe how the fixed and variable costs of these projects will be passed on to Kentucky Power's ratepayers.

b. Explain how the pass through of these costs is expected to change if the existing Pool Agreement is terminated.

15. Refer to page 9 of the Munsey Testimony, lines 12-19, where four projects at other AEP facilities that have already been placed in service are identified. Kentucky Power is requesting to incorporate the costs associated with these projects into the environmental surcharge report for inclusion in its environmental surcharge. Explain

why these projects have not been previously incorporated into Kentucky Power's environmental surcharge.

16. Refer to page 12 of the Munsey Testimony, lines 3-4. It states that the "Company's utility plant 15-year depreciation rate of 6.67%" was used. Provide the basis of the 15-year depreciation rate and explain whether this depreciation rate has been previously approved by the Commission.

17. For the capital costs imbedded in the costs of the Big Sandy Unit 2 FGD system in Exhibit LPM-1, provide a breakdown of the cost for the major components in the system in total dollar amounts and in dollars per kW.

18. Refer to Exhibit LPM-1. The Preliminary Scrubber Analysis 2004-2006 amount is $15,212,425.

a. Confirm whether this amount pertains to preliminary scrubber analysis for the years 2004 to 2006.

b. Provide a breakdown of the $15,212,425 identifying the types of costs that have been incurred.

c. Explain whether this amount is for costs incurred for preliminary scrubber analysis only at the Big Sandy plant or if it includes any costs allocated to Kentucky Power by AEP of an AEP system-wide study of preliminary scrubber analysis.

d. If the answer to part a. of this Item is yes, explain whether any of this cost is applicable to the scrubber technology now proposed for Big Sandy Unit 2.

19. Refer to Exhibit LPM-1. Provide separate breakdowns of the proposed annual operation expense of $46.067 million and annual maintenance expense of $2.6 million which identifies the types of costs that make up these estimates.

20. Refer to Exhibit LPM-2. The heading of column 4 is "Capital Costs of Associated Utility Revenues." In Kentucky Power's environmental surcharge filings, the environmental surcharge factor on ES Form 1.00 is determined by dividing the Net KY Retail Expense amount on line 8 by the KY Retail Revenue, from ES Form 3.30, line 9.

a. Associated Utilities Revenues is shown on line 3 of the top portion of ES FORM 3.30, but is not considered in the calculation of the environmental surcharge factor on ES Form 1.00. Explain why the exhibit includes a calculation to recover environmental costs applicable to Associated Utilities Revenues.

b. Based on the current approved methodology for environmental costs recovery in Kentucky Power's environmental surcharge report, explain whether environmental costs associated with Associated Utilities Revenues are recovered through base rates.

c. If the answer to part b. of this Item is yes, explain whether the monthly environmental surcharge base rates shown on the proposed tariff, on page 1 of Exhibit LPM-15, should be revised to include environmental costs applicable to both KY Retail Revenues and Associated Utility Revenues.

21. Refer to Exhibit LPM-6. Provide the calculation supporting the 29.89 percent in column 7 under the heading "OPCo or I&M Percentage."

22. Refer to page 4 of the Direct Testimony of Robert L. Walton ("Walton Testimony"), lines 17-19. It states, "[t]he Big Sandy Unit 2 FGD retrofit project will be executed using the same phased approach that has been successfully employed by AEP on many past projects. The phased approach begins with Phase I, which consists primarily of a feasibility study." Considering the $15,212,425 cost of the preliminary

scrubber analysis of 2004-2006 on Exhibit LPM-1, explain whether more than one approach was considered for the proposal to construct a scrubber at Big Sandy Unit 2.

23. Refer to page 5 of the Walton Testimony, lines 3-5. It states, "[s]ince 2004, AEP has implemented this phased approach in the installation of FGD systems on over 8,400 MW of generation and SCR ["Selective Catalytic Reduction"] systems on approximately 2,400 MW."

a. Provide the names of the affected generating units and the generating capability of each unit.

b. Provide the length of time to install each FGD from the start of Phase I to the in-service date of each FGD.

c. Provide the in-service date of each affected unit's FGD.

d. Provide the cost per kW for each affected unit's FGD.

e. Provide a copy of the project schedule for each unit in a form comparable to Exhibit RLW-1.

24. Refer to page 5 of the Walton Testimony, line 14. It states, "[t]he project is currently in Phase I." Explain when Phase I began.

25. Refer to page 5 of the Walton Testimony, lines 21-22.

a. Explain whether an architect/engineer ("A/E") has been engaged for this project? If so, who is the A/E?

b. Describe the process of how the A/E was, or will be, selected.

26. Refer to page 5 of the Walton Testimony, lines 20-23. It states, "[t]he formal process begins with the preparation and approval of a Capital Improvement Requisition (CI) after which an architect/engineer (A/E) is engaged to perform the

engineering, design, and feasibility studies for Phase I and the ensuing phases of the project."

a. Provide a copy of the AEP Board approved CI.

b. Provide the date the CI was approved by the AEP Board.

27. Refer to page 9 of the Walton Testimony, lines 5-7. In discussing Total Evaluated Cost ("TEC"), it states, "[t]he final award is based on the TEC and safety performance of those bidders, along with ancillary considerations such as a financial risk assessment, any pricing discounts offered for multiple-unit awards, negotiated shared risk/reward programs, and similar factors."

a. Describe the extent to which AEP encountered any of these factors in conjunction with its previous scrubber construction projects.

b. If the answer is yes to part a. of this Item, identify which factors were encountered and provide the additional cost to the project affected.

c. Explain whether any of the factors might come into play in installing the type of scrubber and environmental facilities planned at Big Sandy Unit 2.

28. Refer to page 10 of the Walton Testimony, lines 2-16. It discusses AEP's cost management process. For each of the FGD systems discussed on page 5 of the Walton Testimony, line 4, provide the Phase I estimated cost and the completed in-service cost.

29. Refer to page 11 of the Walton Testimony, lines 16-19, which indicate that the "FGD System Equipment Supplier is selected from a competitive evaluation process based on AEPSC ["AEP Services Company"] performance and technical specifications. A similar process is utilized for the selection of construction labor companies to perform

the field installation of the equipment." Does AEP select different vendors throughout its fleet, or the same overall vendor for familiarity with the product/vendor?

30. Refer to page 15 of the Walton Testimony, lines 21-23, which indicates that technical and economic evaluations were performed to compare and contrast the wet FGD and dry FGD technology options that may be applied while burning coals with different sulfur contents, up to 4.5 lbs. SO_2/mmBtu.

a. Describe in detail the impact the sulfur content played in selecting the appropriate SO_2 removal technology.

b. Would the desulfurization selection process change if the sulfur level changes?

c. Provide examples of technologies which will meet the EPA mandates as related to high and low sulfur coal.

31. Refer to page 16 of the Walton Testimony, lines 21-22, which supports the position that a wet FGD is less capital intensive than a dry FGD. Provide a comparison of the operation and maintenance costs of the two FGD processes.

32. Refer to the Walton Testimony, page 17, line 22, to page 18, line 10. Provide the projected in-service cost of the equipment listed.

33. Refer to page 19 of the Walton Testimony, lines 9-12, which indicates that the Class 4 estimate for the dry FGD installation is -15 percent to +20 percent of the $839 million estimate. What confidence level, in terms of probability, has Kentucky Power and/or AEP associated with this estimate range?

34. Refer to page 19 of the Walton Testimony, line 17. Clarify whether the 20 percent contingency is included in the $839 million estimate.

35. Refer to page 21 of the Walton Testimony, lines 10-14. It states that the NID dry FGD technology has been installed on 1,800 MW of capacity in the US.

a. Identify the units equipped with this technology and their locations.

b. Describe the "due diligence" that AEP performed with regard to the dry FGD technology and provide a copy of the due diligence report.

36. Refer to page 22 of the Walton Testimony, lines 15-17. It states that the wet FGD at Big Sandy Unit 2 was abandoned due to increases in the cost estimate "primarily attributed to increases in labor and material costs" despite AEP's efforts to mitigate this risk. Given the expected increase in demand for the installation of environmental compliance equipment in the industry in the upcoming years, explain thoroughly how Kentucky Power can be confident that a similar scenario will not occur.

37. Refer to page 22 of the Walton Testimony, lines 22-23. It states that there was a decrease in the projected price spread between low and high sulfur coal that effectively eliminated any cost savings associated with using a higher sulfur coal. Provide those price projections.

38. Refer to Exhibit RLW-1, which indicates that the Title V Air Review and Approval will take 12 months. The McManus Testimony at page 17, lines 10-12, states that issuance of the air permit will take up to 18 months from the date of application. Clarify the divergence in time estimates.

39. Provide the following operational information for Big Sandy Units 1 and 2:

a. The number of normal cycles (stops and starts).

b. The number of emergency trips and starts.

c. Capacity Factor for the last five years.

d. Heat Rate for the last five years.

e. Major internal and minor outages including the major projects completed during each outage for the last 10 years.

f. An outline of the major availability and performance detractors for the last five years.

g. A condition assessment that includes:

1) Condition of turbine;

2) Condition of generator;

3) Condition of boiler; and

4) Condition of balance of plant equipment.

h. Any formal life assessment or extension reports.

40. Recognizing that AEP has no experience with installing the proposed NID dry FGD technology, describe how confident it is with the accuracy of the cost and schedule estimates.

41. Explain the difference in the in-service date on the Walton Testimony, page 19, line 2, of the second quarter of 2016, and the December 2015 date in the Application, at paragraph 12, page 6.

42. Explain whether Kentucky Power intends to manage the Big Sandy Unit 2 dry FGD project on a multi-prime basis or Engineering, Procurement and Construction basis.

43. Provide an organization chart of the AEPSC construction management team that will be managing the proposed dry FGD project.

44. Describe Kentucky Power's plans for retiring and decommissioning Big Sandy Unit 1. Will the unit be demolished or will the structure and selected components be reutilized as a natural gas fired combined cycle unit.

45. Explain whether Kentucky Power plans to use Electro-Static Precipitators ("ESP") with the NID technology. If the ESP is eliminated, what is the resultant reduction in station service load?

46. Based on the January 5, 2012 Conference, what is the expected impact of coal blending on the steam generator, air heaters, and SCR system?

47. Refer to page 9 of the Direct Testimony of Scott C. Weaver ("Weaver Testimony"), lines 27-29. For modeling purposes, the cost to comply with Coal Combustion Residual ("CCR") regulations has been estimated at $48 million. Provide support for this estimate.

48. Refer to pages 11-12 of the Weaver Testimony, Table 1. Provide the Strategist model runs for each option and a detailed discussion of the main assumptions and economic drivers for each option run.

49. Refer to pages 11-12 of the Weaver Testimony, Table 1, specifically, Options #2 and #3.

a. Explain the extent to which Kentucky Power considered the purchase of the simple cycle combustion turbine ("SCCT") generating units near the Big Sandy station and whether any attempt was made to negotiate a purchase.

b. Explain whether converting the SCCTs to combined cycle units would be uneconomical relative to building new units.

c. Provide a table showing the prices of natural gas used in the Strategist model to determine the economic viability of Options #2 and #3 and an explanation of the sources of the gas price data.

d. Provide a demonstration of and explanation of how sensitive the analyses results are to variations in the price of natural gas.

50. Refer to pages 11-12 of the Weaver Testimony, Table 1, at Option #4.

a. Explain why only five and ten year power purchase options were modeled.

b. Explain whether Kentucky Power issued a Request For Quote ("RFQ") to purchase market power.

c. If the answer is yes to part b. of this Item, provide a summary of the bids that were received and Kentucky Power's analysis of the bids leading to either acceptance or rejection.

d. If the answer to part b. of this Item is no, explain.

51. Refer to pages 11-12 of the Weaver Testimony, Table 1. It discusses four options available to Kentucky Power to address unit disposition decisions facing the Big Sandy units. In several of the options there is a statement "with incrementallyrequired capacity and energy needs purchased for calendar year 2015—and prospectively—from the PJM market". Provide a response and a complete explanation of the following:

a. If Kentucky Power remained in the AEP Pool, would that change its analysis or conclusions about building a scrubber at the Big Sandy Unit 2?

b. If Kentucky Power was in another pooling arrangement similar to the Corporate Separation analysis performed earlier this decade, explain whether that would have changed Kentucky Power's analysis or conclusions about building a scrubber at the Big Sandy Unit 2.

c. Given that Kentucky Power's customers have been supporting (the average cost along with an investment rate of 16.44 percent) OPCo's generating facilities, including the environmental facilities, through the FERC-approved Pool Agreement, should the FERC rule that some amount of the OPCo generation remain with Kentucky Power, explain whether this would have changed Kentucky Power's analysis or conclusion about building a scrubber at Big Sandy Unit 2.

52. Refer to pages 12-14 of the Weaver Testimony.

a. Explain when Kentucky Power became aware of the necessity to curtail the Big Sandy units for an interim period to comply with the CSAPR SO_2 "Phase I" requirements.

b. Identify all other AEP affiliate generating units that will have to be curtailed on an interim basis to comply with either CSAPR or the MACT requirements.

c. Explain whether Kentucky Power intends to curtail operations at the Big Sandy plant during the 2012-2016 timeframe.

d. Explain the rationale for the decision to curtail the Big Sandy units in lieu of other AEP units. If the answer is related to either AEP or PJM system reliability, provide the power and transmission studies (including a narrative explanation of the study results) that support the decision.

e. When the Big Sandy units are curtailed, explain how Kentucky Power expects the power to be replaced and at what assumed cost.

f. Since Kentucky Power knew that SO_2 mitigation would be required as a result of the 2007 Consent Decree, explain why it did not commence the process of satisfying those requirements sooner.

g. If a wet FGD had been installed at Big Sandy as soon as possible following the 2007 Consent Decree, explain what additional mitigation efforts, if any, would now be required to satisfy CSAPR, MACT, CCR, and other EPA requirements.

53. Refer to page 13 of the Weaver Testimony, lines 4-13. It discusses the anticipated necessary timeframe to obtain Commission approvals, permit, engineer, and procure materials and components. Provide the following:

a. Explain when Kentucky Power or AEP became aware that, for continued operations of the Big Sandy units, a scrubber would need to be installed.

b. If the Big Sandy Unit 2 scrubber was operational before January 2012, explain whether the unit's generation would need to be constrained or curtailed.

c. Explain what increased/decreased costs for energy and capacity Kentucky Power expects to incur during the constrained or curtailed operational period.

d. Explain how these costs are recovered or how the credits would be flowed back to the ratepayers.

e. In order for the Big Sandy Unit 2 scrubber to have been operational on or before January 2012, when would it have been necessary to begin Phase I of the construction?

54. Refer to page 14 of the Weaver Testimony, lines 1-9. It states, "[a]s indicated above, it is anticipated that the necessary time to obtain Commission approvals, permit, engineer, procure materials and components, construct and commission a DFGD retrofit would place the in-service date, for economic modeling purposes, at approximately June 1, 2016. Given that, and the limiting factors associated with the EGU ["Electric Generating Unit"] MACT rule and the NSR Consent Decree, it was then assumed that, for modeling purpose, Big Sandy Unit 2 would be removed from service effective January 1, 2016 for the period leading up to the beginning of the normal retrofit "tie-in" outage which would occur in approximately the April/ May 2016 timeframe."

a. Based on AEP's prior scrubber installation experience, provide, by generating unit, the average length of time the units were down for "tie-in".

b. Explain whether these units with scrubber installation were also down three months prior to the "tie-in" timeframe.

55. Refer to page 14 of the Weaver Testimony, lines 5-8, and Exhibit SCW-1.

a. For PJM members participating in the Reliability Pricing Model ("RPM") and electing to meet their capacity resource obligations through the Fixed Resource Requirement ("FRR") construct and then are unable to meet their capacity obligations through their own generation assets, explain whether the members are prohibited from meeting capacity obligations by purchasing that capacity through bilateral or other contractual means outside PJM or with a PJM member directly. In other words, if a company elects FRR and cannot meet its obligations, is it required to fulfill its obligations through PJM and to use Locational Marginal Pricing ("LMP") as the pricing mechanism?

b. Explain whether there are any transmission constraints preventing Kentucky Power from obtaining power to help meet both its capacity and energy requirements from outside PJM and, if so, identify those constraints.

56. Refer to the Weaver Testimony, page 14, line 17, to page 15, line 4. It discusses the retrofit of dry FGD and SCR technology at the Rockport Generating Station ("Rockport") for modeling purposes.

a. Explain when a commitment for a course of action at Rockport will be made.

b. Explain how the dates used in the baseline modeling affect the modeling results. For example, if the installation dates are accelerated or delayed by two years, provide the results of the base line modeling.

c. Explain whether the Rockport units are required to be constrained or curtailed until the dry FGDs and SCRs are placed in service.

57. Refer to page 14 of the Weaver Testimony, lines 17-23.

a. Thoroughly describe the "Rockport units' unique NSR Consent Decree requirements."

b. Explain whether the statement means that Kentucky Power is only responsible for expenses associated with the January 1, 2016 dry FGD retrofit and not the "more aggressive" January 1, 2014 retrofit with the SCR installed by year end 2019.

c. For each Rockport unit, provide a breakout of what retrofit expenses will be either allocated to Kentucky Power or paid by Kentucky Power through capacity and energy purchases, through the long term purchase contract only, and the timing of any such payments.

d. Explain how Kentucky Power plans to replace 15 percent of the power and capacity it obtains from the Rockport units when the long term purchase contract expires in 2022.

58. Refer to page 15 of the Weaver Testimony, lines 7-18. It discusses the initial economic evaluations performed from the perspective of a "stand-alone" Kentucky Power.

a. Explain whether there were assumed capacity and energy costs or credits flowing to/from affiliate AEP operating companies via the Pool Agreement. How would the results and/or conclusions of the economic study change if capacity and energy costs or credits were flowing to/from affiliate AEP operating companies via the Pool Agreement.

b. Explain whether AEP or Kentucky Power have made any previous filings with Commission indicating that the current AEP Pool would be terminated.

c. If the answer to part b. of this Item is yes, explain when AEP or Kentucky Power plans on requesting the termination of the AEP Pool at FERC and this Commission.

59. Refer to page 15 of the Weaver Testimony and Exhibit SCW-1.

a. Explain whether Kentucky Power is contemplating forming another pool agreement with any other AEP affiliates. If yes, provide the anticipated timing of any such agreements, the AEP affiliates, the specific benefits of such an agreement to Kentucky Power and its ratepayers, and how such an agreement will affect the modeling results presented in the Application.

b. If another pool agreement is formed, identify the environmental compliance costs incurred by its AEP affiliates, if any, that will likely be borne by Kentucky Power ratepayers.

c. If another pool agreement is formed, explain the validity of assuming, in the Application, for modeling purposes, that Kentucky Power is a stand-alone company.

d. Describe the benefits specific to Kentucky Power and to each of the other AEP affiliate companies that may be included in a new pool agreement.

60. Refer to page 18 of the Weaver Testimony, line 5. It discusses using a proxy for an estimated Kentucky Power weighted average cost-of-capital. Describe the

estimated Kentucky Power weighted average cost-of-capital used in the economic analysis.

61. Refer to page 21 of the Weaver Testimony, lines 1-5. It discusses a critical input parameter that includes the installed costs of the environmental retrofits. Explain the results of the economic analysis and conclusion if the installed costs of the required environmental retrofits come in at 10 to 20 percent above what is currently reflected in this filing.

62. Refer to page 22 of the Weaver Testimony. Explain the anticipated delivered price differences for coal with varying sulfur contents and the effects FGD technology selection has on the modeling results for Option #1.

63. Refer to pages 23-24 of the Weaver Testimony.

a. Explain why a specific combined cycle ("CC") design including duct firing and chillers was assumed in the analyses for Options #2 and #3.

b. Explain why a specific size unit was assumed in each analysis and identify any economies of scale based on unit size.

c. Since Options #2 and #3 also assumed indicative cost estimates and performance parameters associated with gas pipeline infrastructure and pressuring and metering equipment to receive gas, explain why the option of using the nearby existing simple cycle facility was not considered. Given the lack of existing CC generating facilities, it would seem that this site possesses the necessary infrastructure to support new or converted gas turbines.

64. Refer to page 24 of the Weaver Testimony, Table 2.

a. Provide a detailed explanation and break out of costs referenced in columns (c) and (e) for each row of the chart.

b. Confirm the dollar amounts in columns (d) and (g) are total cost installed and not the dollar amount per kW installed.

c. If not provided above, provide a detailed explanation of what additional costs are included in Modeling CCR-related.

d. If not provided above, provide a detailed explanation of what additional owner's costs are allocated from OPCo, why the allocation varies between Options #1 through #3, and why they must be accepted.

65. Refer to pages 25-26 of the Weaver Testimony, regarding the discussion of Option #4, the "(Full) Capacity Replacement Purchase."

a. Explain whether a RFQ solicitation for capacity and energy was not also issued as an additional alternative to full reliance on the PJM market capacity and energy and pricing.

b. Explain the rationale for only considering full market participation in PJM for the purchase of power.

c. If a RFQ solicitation was issued, provide the analysis of the bids including the terms of the bids and why each bid received was not acceptable.

d. If a RFQ solicitation was not issued seeking capacity and energy, explain the rationale for not seeking such a solicitation.

66. Refer to page 27 of the Weaver Testimony.

a. Since AEP and Kentucky Power are stand-alone generators for their own customers within the PJM system, explain the relevance of the LMP clearing prices for gas fired combined cycle combustion turbines ("CCCTs") and where those units settle in the PJM dispatch stack.

b. Under either Option #2 or #3, explain how the cost of generation and transmission is determined and passed on to Kentucky Power retail customers.

67. Refer to pages 28-30 of the Weaver Testimony.

a. For each of the Options #1 through #4, provide the results of evaluating each of the long term commodity pricing views on each Option.

b. Provide a detailed explanation of how the economic costs associated with Option #1 change relative to Options #2 through #4 once a carbon tax becomes effective.

68. Refer to pages 30-40 of the Weaver Testimony and Exhibit SCW-1, Figure 1-1, page 13 of 14, and Exhibit SCW-4.

a. Explain how the AEP Fundamental Analysis group derived and/or obtained PJM forward capacity and energy prices for Options #2 through #4.

b. Explain why only power purchases through PJM using PJM mechanisms were modeled.

c. If other power purchase options were considered, including but not limited to purchases from the gas fired generating station residing near the Big Sandy station, provide a description of those options.

d. Identify and describe the PJM LMP area in which Kentucky Power is modeled to participate and describe all factors that are setting prices, including but not limited to seasonality, load centers, unit location and availability to meet load, and reliability requirements.

e. Within PJM, generally and specifically the LMP area within which Kentucky Power participates, explain whether and how LMP set prices are affected and modeled by the timing of generation units either being curtailed permanently or curtailed temporarily during a retrofit from 2012 to 2020.

f. For each of the Options modeled, explain whether Kentucky Power being in another power pool would or would not affect the results and, if so, explain how the results would be affected.

69. Refer to pages 31-34 of the Weaver Testimony, where it discusses the retirement and replacement of Big Sandy Unit 2 with a new CC facility (Option #2) and the retirement and replacement of Big Sandy Unit 2 with the repowering of Big Sandy Unit 1 as a CC facility (Option #3) have higher Cumulative Present Worth costs ("G" Revenue Requirements).

a. Provide the date the economic analysis was completed that supported these conclusions.

b. Describe all the circumstances or inputs that have changed between when the economic analysis or studies were performed that supported the plan to retire both Big Sandy units and rebuild one as a 640 megawatt natural gas plant and today's plan to retrofit Big Sandy Unit 2 with a dry FGD.

70. Refer to page 36 of the Weaver Testimony, lines 12-17. It states, "such advance recovery (from 20 years to 15 years) of these environmental investments would neither add significant costs to the Base/"Option #1" Big Sandy Unit 2 retrofit economics in absolute terms nor—as previously reviewed—would it cause the relative economics with either of the replacement-build alternatives (Option #2 or #3) to be significantly influenced." Explain whether the same conclusion would hold true under a delay recovery (from 20 years to 30 years) of these environmental investments.

71. Refer to pages 39-40 of the Weaver Testimony.

a. Explain whether long term capacity and energy purchases are allowed or even possible within PJM and, if so, how such purchases are accomplished and priced.

b. Explain how both the projected price of capacity and the price of energy under PJM's RPM are determined and used in the model.

c. In the PJM LMP area in which Kentucky Power would participate, describe how much capacity and energy is available that is in excess of what is needed to satisfy load and set the marginal price.

72. Refer to pages 40-42 of the Weaver Testimony, specifically the discussion focusing on natural gas combined cycle units.

a. Explain whether the discussion means that Kentucky Power did not attempt to either solicit any long term power (sourced from natural gas combined cycle units or otherwise) from any source under any conditions or to purchase gas generating assets and only assumed that the cost of purchased power would be equal to the cost of a new combined cycle unit.

b. Explain why the discussion focuses on CCCTs only, and not other alternative types of fuel or technology.

c. If not already addressed above, explain specifically why the option of purchasing the natural gas combustion turbines located near the Big Sandy station and either converting them to a combined cycle units or adding a combined cycle unit to the existing facility are not viable options.

d. If not addressed above, since Kentucky Power is short on peaking capacity, explain whether its potential partners in a new power pool have excess peaking capacity that would benefit Kentucky Power.

73. Refer to the Weaver Testimony, Exhibit SCW-1, page 4. Was a range, or ranges, of projected peak demands and internal loads over the forecast period used in the utility disposition models using Strategist? If not, explain. If a range or ranges of peak demand and internal load were utilized, provide them.

74. Refer to the Weaver Testimony, Exhibit SCW-2, page 2. What is the basis for the $15.08 per metric tonne estimate for CO^2 in the base case in 2022? What escalation factor was used for subsequent years and what is the basis for the escalation?

75. Refer to Weaver Exhibit SCW-2, page 2. The capacity value for all scenarios increases from $27.73/MW-Day in 2013 to $126.00/MW-Day in 2014. Explain the increase in capacity value beginning in 2014. Describe how the capacity value was escalated through 2030 in the base case and each of the scenarios.

76. Provide in an electronic format the Strategist model input files used to generate the following exhibits. The response should include references to the source of the input data.

a. Exhibit SCW-4A;

b. Exhibit SCW-4B;

c. Exhibit SCW-4C;

d. Exhibit SCW-4D; and

e. Exhibit SCW-4E.

77. With the proposed retirement of Big Sandy Unit 1 in 2015, coupled with other anticipated unit retirements in the region, does Kentucky Power anticipate a short-fall in generation capacity?

78. Refer to pages 7-8 of the Direct Testimony of Ranie K. Wohnhas ("Wohnhas Testimony").

a. Does the discussion imply, under Option #1, that Kentucky Power would purchase all of the high sulfur coal to be burned at the Big Sandy units from Eastern Kentucky and, if not, from where would it purchase such high sulfur coal?

b. If not provided elsewhere, provide the projected coal purchase prices for the various sulfur contents, projected transportation costs, and delivered prices at the Big Sandy station used in the modeling exercises supporting Option #1.

79. Refer to page 8 of the Wohnhas Testimony, lines 7-11.

a. Explain whether Kentucky Power believes that a decision in this case should be based on any socioeconomic factors.

b. If the answer to part a. of this Item is yes, provide a list of the socioeconomic factors that Kentucky Power believes should be considered.

80. Refer to page 8 of the Wohnhas Testimony, line 14. Provide the calculations supporting the 86 jobs and the $6.0 million in annual compensation.

81. Refer to page 8 of the Wohnhas Testimony, line 16-17. Provide the calculations supporting the annual reductions in payroll and property taxes of $3.2 million and $461,000, respectively.

82. Refer to page 8 of the Wohnhas Testimony, lines 18-19. Provide the source and calculations supporting the $75 per ton coal cost and the approximately $165 million per year injected into the local economy.

83. Refer to page 8 of the Wohnhas Testimony, lines 20-21. It states, ". . . with the indirect impact on mining and transportation (500 jobs, $8 million in severance taxes, and $25 million in wages per year) of the gas options."

a. Provide the calculations that support the 500 jobs, $8 million in severance taxes, and the $25 million in wages per year.

b. Explain whether Kentucky Power anticipates that all coal burned at Big Sandy Unit 2 after the dry FGD is installed will come from Kentucky sources.

84. Refer to page 9 of the Wohnhas Testimony, lines 3-13.

a. If not provided elsewhere, provide the preliminary analysis which concluded that Big Sandy Units 1 and 2 would be retired with Big Sandy Unit 1 being repowered as a CCCT unit, including a listing and discussion of the reasonableness of all assumptions and any presentations made to management supporting the results of the analysis.

b. If not provided elsewhere, provide a detailed comparison of all assumptions made in the preliminary analysis and in the subsequent analysis supporting Option #1. Changes in primary assumption drivers should be highlighted and discussed specifically.

85. Refer to page 9 of the Wohnhas Testimony, lines 8-13. It states, "[t]hose plans based upon a preliminary analysis that indicated repowering of Big Sandy Unit 1 would be the least cost alternative. Subsequently, and as explained by Witness Walton, a more robust and detailed analysis was performed on the four alternatives. That completed analysis revealed that contrary to the preliminary review, the low cost is installation of a DFGD on Big Sandy Unit 2."

a. Explain when the preliminary analysis first began.

b. Explain when the preliminary analysis was completed.

c. Provide the cost of the preliminary analysis.

d. Provide who requested that the preliminary analysis be performed.

e. Explain what circumstances changed between the conclusion of the preliminary analysis and the completed analysis that revealed the low cost alternative is to install a dry FGD on Big Sandy Unit 2.

86. Refer to page 9 of the Wohnhas Testimony, lines 22-23. Identify the likely sources for the 4.5 lbs. SO_2/MMBtu coal.

87. Refer to the Wohnhas Testimony, page 13, lines 12-17 and 21, to page 14, line 7.

a. Provide the type of FGD that was the topic of the preliminary investigation.

b. Provide who performed the investigation, for example AEPSC employees or an outside consultant.

c. Explain whether the FGD investigation performed was strictly for the Big Sandy plant or for other AEP generating plants. If it included other plants, provide the names of those plants.

d. Provide a detailed description of the type of work performed and a breakdown of the $15,212,425 by type of costs.

e. Explain whether there were more effective technologies developed between 2006 and the date of the completed analysis, as referred to on lines 2 and 3 on page 14 of the Wohnhas Testimony.

88. Refer to pages 14-15 of the Wohnhas Testimony.

a. Explain the basis, whether it be a study or analysis, for the 15-year depreciation period.

b. Provide the current depreciation rates utilized for the generating equipment at the Big Sandy plant.

c. Provide, by generating plant, the depreciation periods used for the scrubbers already in service on the AEP System.

89. Refer to pages 14-15 of the Wohnhas Testimony.

a. Under Option #1, what is the expected remaining useful life of the existing equipment?

b. Under Option #1, if the expected remaining life of the existing equipment is longer than 15 years, explain why it would not be appropriate to match the depreciation lives of the new environmental control equipment with the expected remaining lives of the existing equipment.

c. Provide the rationale for thinking that the Commission would not allow the continued recovery of all authorized expenses.

d. For Options #1 through #4, explain whether the depreciation lives of the equipment in the various options were the same. If not, why.

90. Explain how the 15 year depreciation period for the Big Sandy scrubber referred to on pages 14-15 of the Wohnhas Testimony compares with the statement made on page 15 of the Weaver Testimony, lines 14-18, that states "these evaluations were performed over a 30-year economic study period (2011 through 2040) in the Strategist tool so as to emulate the potential life-cycle of the respective asset alternatives as well as in recognition of the various "down-stream" impact on KPCo overall resource planning needs."

91. Refer to the Wohnhas Testimony at page 15, lines 1-5. One of the reasons given for depreciating the FGD at Big Sandy Unit 2 over 15 years is to reduce the risk of stranded investment in the future.

a. What is Kentucky Power's assessment of the risk of the FGD becoming a stranded investment?

b. Explain why existing customers should pay for this future risk.

92. Refer to page 16 of the Wohnhas Testimony, lines 15-20. Explain how Kentucky Power purposes to recover the cost of CSAPR emission allowances related to sales to affiliates and off system sales.

93. Refer to page 17 of the Wohnhas Testimony, lines 1-4.

a. The estimated expense for CSAPR emission allowances for 2012 is $6.2 million. Provide support for this estimate.

b. For 2012, a gain of $650,000 from the sale of NO_x allowances under CSAPR is shown. Provide support for this estimate.

94. Explain whether AEP has placed scrubbers on any 800 MW or 1,300 MW units on its system and, if so, identify the plant and unit. If any have been installed, provide the average time to design, construct, and install the scrubbers on the 800 MW or 1300 MW units, by plant and unit.

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cc: Parties of Record

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